



บริษัท ปตท.สผ. สยาม จำกัด

รายงานผลการปฏิบัติตามมาตรการป้องกันและแก้ไขผลกระทบสิ่งแวดล้อม และมาตรการติดตามตรวจสอบผลกระทบสิ่งแวดล้อม
โครงการผลิตปิโตรเลียมแหล่งปริอกระเทียม ระยะที่ 2 และพื้นที่ใกล้เคียง แปลงเอส 1 จังหวัดกำแพงเพชร พิจิตร และพิษณุโลก
ฉบับเดือนมกราคม – ธันวาคม พ.ศ.2565

ภาคผนวกที่ 14
เอกสารบันทึกการตรวจสอบสุขภาพประจำปี

สรุปผลการตรวจสุขภาพประจำปี 2565 ของพนักงานผู้ปฏิบัติงานโครงการ S1

มีข้อมูลและรายละเอียดของผลการตรวจสุขภาพดังนี้

1. จำนวนพนักงาน S1 ที่ปฏิบัติงานที่ฐานปฏิบัติการ S1 ทั้งหมด 356 คน เข้ารับการตรวจร่างกายทั้งหมด 100 %

2. โดยเข้ารับบริการการตรวจร่างกายแยกตามสถานพยาบาลที่บริษัทได้ดำเนินการประสานงานไว้แล้ว ดังนี้

- เครือโรงพยาบาลกรุงเทพ จำนวน 348 คน คิดเป็น 97.75 %
- โรงพยาบาลวิภาวดี จำนวน 7 คน คิดเป็น 1.97 %
- โรงพยาบาลอื่นๆ จำนวน 1 คน คิดเป็น 0.28 %

3. จากจำนวนผู้เข้ารับการตรวจร่างกายจำนวน 356 คน แบ่งตามช่วงอายุ ตามแผนการตรวจร่างกายของบริษัทได้ ดังนี้

- ช่วงอายุน้อยกว่า 35 ปี มีจำนวน 71 คน คิดเป็น 19.94 %
- ช่วงอายุตั้งแต่ 35 ปี ถึง 44 ปี มีจำนวน 172 คน คิดเป็น 48.31 %
- ช่วงอายุตั้งแต่ 45 ปีขึ้นไป มีจำนวน 113 คน คิดเป็น 31.74 %

4. ผลการตรวจสุขภาพ

4.1 ผลการตรวจสุขภาพทั่วไป

- มีภาวะความดันโลหิตสูง จำนวน 51 คน คิดเป็น 14.33 % โดยความรุนแรงของระดับความดันโลหิตที่พบอยู่ในระดับต่ำทั้งหมด โดยจากการติดตาม พนักงานได้เข้ารับคำแนะนำในการปฏิบัติตัวและติดตามโรคเรียบร้อยแล้ว
- มีภาวะระดับน้ำตาลในเลือดสูงเกินเกณฑ์มาตรฐานโรคเบาหวาน จำนวน 14 คน คิดเป็น 3.93 % โดยจากการติดตามพนักงานได้เข้ารับคำแนะนำในการปฏิบัติตัวและติดตามการรักษาอย่างต่อเนื่องแล้ว
- มีภาวะไขมันในเส้นเลือดสูง จำนวน 229 คน คิดเป็น 64.33 % โดยมีความรุนแรงของระดับไขมันในเลือดสูง เป็น ดังนี้
 - ไขมันในเลือดสูง ความรุนแรงระดับต่ำ จำนวน 112 คน คิดเป็น 31.5 % (ของผู้เข้ารับการตรวจร่างกาย) โดยจากการติดตาม พนักงานได้เข้ารับคำแนะนำในการปฏิบัติตัวและติดตามโรคแล้ว
 - ไขมันในเลือดสูง ความรุนแรงระดับกลาง จำนวน 74 คน คิดเป็น 20.8 % (ของผู้เข้ารับการตรวจร่างกาย) โดยจากการติดตาม พนักงานได้เข้ารับคำแนะนำในการปฏิบัติตัวและติดตามโรคแล้ว และมีพนักงานบางส่วนแพทย์ประจำโรงพยาบาลได้พิจารณาให้รับประทานยาเพื่อรักษาโรค
 - ไขมันในเลือดสูง ความรุนแรงระดับสูง จำนวน 43 คน คิดเป็น 12.1 % (ของผู้เข้ารับการตรวจร่างกาย) แพทย์ประจำโรงพยาบาลได้พิจารณาให้รับประทานยาเพื่อรักษาโรคและติดตามรักษาต่อเนื่อง

- การตรวจคัดกรองภาวะวัณโรคปอดจากการเอกซเรย์ปอดประจำปี พบลักษณะเอกซเรย์ผิดปกติที่เข้าได้กับการวินิจฉัยวัณโรคปอด จำนวน 1 ท่าน โดยได้มีการส่งปรึกษาอายุรแพทย์โรคทางเดินหายใจและรักษาตามมาตรฐานการรักษาวัณโรคปอดเรียบร้อยแล้ว ขณะนี้พนักงานสามารถกลับมาปฏิบัติงานได้ตามปกติ และได้มีการสืบสวนข้อมูลการระบาด ไม่พบว่ามีกรณีเจ็บป่วยไปยังเพื่อนร่วมงานและคนใกล้ชิดในครอบครัว

4.2 ด้านอาชีวอนามัย

- การตรวจหาสารเบนซีนในปัสสาวะ (ยึดฐานข้อมูลจาก S1 Health risk assessment) พนักงานเข้ารับการตรวจ 217 คน คิดเป็น 100% โดยผลพบค่าเบนซีนผิดปกติเกินเกณฑ์มาตรฐาน 1 คน ซึ่งพนักงานได้เข้ารับการสืบค้นไม่พบว่าเกิดจากการทำงานและเก็บปัสสาวะซ้ำพบว่าค่ากลับมาอยู่ในเกณฑ์ปกติ
- การตรวจหาสารไซลีนในปัสสาวะ (ยึดฐานข้อมูลจาก S1 Health risk assessment) พนักงานเข้ารับการตรวจ 4 คน คิดเป็น 100% โดยพบว่าผลปกติทุกคน
- การตรวจหาสารเฮกเซนในปัสสาวะ (ยึดฐานข้อมูลจาก S1 Health risk assessment) พนักงานเข้ารับการตรวจ 4 คน คิดเป็น 100% โดยพบว่าผลปกติทุกคน
- การตรวจหาสารโทลูอีนในปัสสาวะ (ยึดฐานข้อมูลจาก S1 Health risk assessment) พนักงานเข้ารับการตรวจ 66 คน คิดเป็น 100% โดยพบว่าผลปกติทุกคน
- การตรวจสมรรถภาพการไต่ยีน (ยึดฐานข้อมูลจาก S1 Health risk assessment) มีผลการตรวจ 196 คน คิดเป็น 100 % พบผลผิดปกติและทำการตรวจซ้ำทั้งหมด 70 คน โดยผลการตรวจซ้ำพบว่าผลสมรรถภาพการไต่ยีนกลับมาปกติ/คงเดิมจากปีก่อนหน้า 14 คน โดยยังคงผิดปกติ 56 คน ซึ่งจากการสืบค้นและติดตามความผิดปกติพบว่า ไม่เกี่ยวข้องกับการทำงานอย่างชัดเจน แต่ทางทีมแพทย์ยังคงติดตาม พนักงานอย่างใกล้ชิดต่อไป



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ภาคผนวกที่ 15

S1 Emergency Response Plan



PTTEP

PTT Exploration and Production Public Company Limited

S1 Emergency Response Plan

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November 2019

Approval Register

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Review and Approve

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TABLE OF CONTENTS

INTRODUCTION	1
1. PURPOSE.....	1
2. SCOPE.....	2
REQUIREMENTS	4
3. EMERGENCY MANAGEMENT	4
3.1 PTTEP EMERGENCY AND CRISIS CLASSIFICATION.....	4
3.2 S1 EMERGENCY RESPONSE TEAM ORGANIZATION.....	6
3.3 ROLES AND RESPONSIBILITIES	17
3.4 EMERGENCY RESPONSE ACTION	33
3.5 COMMUNICATION DURING EMERGENCY	34
3.6 MUSTER POINT	37
3.7 FACILITIES	38
3.8 PRESS RELEASE	43
3.9 DEACTIVATION AND POST EMERGENCY ACTIONS.....	44
3.10 TRAINING AND EXERCISE	46
3.11 S1 DUTY ROSTER GUIDELINE	46
APPENDICES	51
APPENDIX A: EMERGENCY CALL MESSAGE FROM LKU TELECOM OFFICER	51
APPENDIX B: INITIAL EMERGENCY REPORT FORM.....	52
APPENDIX C: EMERGENCY LOG SHEET	53
APPENDIX D: LOCATION OF PREDETERMINED MUSTER POINTS	55
APPENDIX E: EXAMPLES OF COMMUNICATION TOOLS.....	61
APPENDIX F: EXAMPLE OF S1 DUTY ROSTER.....	65
APPENDIX G: INCIDENT GUIDELINE FOR EMERGENCY SITUATIONS	66
ROLES AND RESPONSIBILITIES	67
DEFINITION AND ACRONYMS	68
REFERENCES	71
REVISION HISTORY	72

INTRODUCTION

1. PURPOSE

In the context of S1 Emergency Response Plan (herein referred to as “Plan”), an emergency is any event, happening with or without advance warning, causing, or which may cause, death or injury, damage to property or the environment or disruption to the community and/ or business within PTTEP S1 onshore operation premises.

The plan is developed for guiding S1 asset personnel to clearly understand the roles and responsibilities of the S1 Emergency Response Team (ERT) during an actual or potential emergency that could cause an impact to S1 asset and its associated stakeholders, especially staff, contractors and surrounding communities. The emergency response shall be actioned to align with the plan as well as related Thai laws and regulations. Apart from S1 ERT member roles and responsibilities and their responsive actions outlined in this document, the emergency preparedness, resources, training and competency, drills & exercises, and recovery/mitigation measures should be also included in this document for ensuring effective emergency management.

- The objectives of emergency response are to:-
- prevent fatalities and injuries;
- reduce damage to plants, facilities, and equipment;
- protect the communities and the environment; and
- accelerate the resumption of normal operations.

The development of the Emergency Response Plan (ERP) begins with a vulnerability assessment. The results of study:-

- Identifies the emergency situations likely to occur and threaten life, environment, community, and S1 operations;
- Identifies means and resources necessary for a given emergency situation;
- Defines S1 emergency organization and key personnel involved with their roles & responsibilities;
- Defines the actions to be taken by S1 ERT members for the emergency preparedness and response;
- Defines the actions to be taken by S1 Community & Media Response Team (CMRT) and Relative Response Team (RRT) for emergency preparedness and response;
- Defines the correct and clear lines of command and reporting in an emergency;
- Describes the guidelines for community handlings in an emergency; and
- Defines interface between S1 ERT and PTTEP corporate Emergency Management Team (EMT) and Crisis Management Team (CMT) and other external parties.

The plan should ensure an integrated response at the appropriate level to any related emergency situations and to minimize the potential impact on People, Environment, Legal Compliance, Asset & Property, and Reputation.

The response of S1 ERT at all levels of the organization will follow the following priorities.

1. Protection of People
2. Protection of Environment
3. Protection of Asset and Property (including infrastructure, machinery, equipment, and facilities)
4. Protection of Reputation and Business

2. SCOPE

This plan applies to all emergency situations occurred within PTTEP S1 and L22/43 Operation premises owned or controlled by PTTEP subsidiaries.

This also includes other relevant agencies that may be requested to provide assistance or expertise to cope with PTTEP S1 emergency situations.

Scope of S1 emergency response covers all operating areas of S1 asset and L22/43 concession areas as well as the activities outside the owned premises, but under the responsibility of S1 asset e.g. land or rail transports, accommodating facilities, etc.

The areas which S1 ERP shall cover are:-

- LKU flow station including crude process area, LPG process, spheres & loading area, and LKU crude depot;
- Production sub-stations including NTM-A, STN-A, and NSG-A;
- Active production well locations;
- Non-productive well locations;
- Flow lines connecting to well locations;
- Bung Pra depot;
- S1 well services workshop;
- S1 material yard and material storage locations;
- Chong Non See (CNS) rail tanker inspection and maintenance workshop; and
- PHS housing compounds.

The activities which S1 ERP shall cover are:-

- Production operation;
- Brownfield construction project activities;

- Drilling activities;
- Well service activities;
- Maintenance & inspection activities;
- Land transports including oil movement, materials and personnel transportation; and
- Other emergency situations which may arise e.g. community concerns, security concerns, natural disasters, etc.

Pertaining to other operations in S1 concession area e.g. drilling, greenfield construction, seismic survey, rig camps, etc. within the scope of S1 concessionaire's liability that have their own emergency organization, they shall establish their own On-Scene Commander (OSC) and responsive team.

The OSC shall report all incidents to S1 Emergency Response Team (ERT) primarily via S1 telecom officer. In any case when situation becomes uncontained by site emergency response organization, S1 ERT comes to take over the command. The OSC constantly report to Deputy Emergency Team Leader (DERTL).

Note: All appendices of this document shall cover:-

- Appendix A: Emergency Call Message from LKU Telecom Officer
- Appendix B: Initial Emergency Report Form
- Appendix C: Emergency Log Sheet
- Appendix D: Locations of Predetermined Muster Points
- Appendix E: Examples of Communication Tools
- Appendix F: Example of S1 Duty Roster
- Appendix G: Incident Guideline for Emergency Situations
- Appendix H: Prompt Cards
- Appendix I: Emergency Contact Lists and Numbers

All appendices of this document shall be reviewed and endorsed by the document owner, Vice President (VP) of S1 Production Operations Department. The appendices will be amended and added without requirements for the document's revision and approval endorsement.

REQUIREMENTS

3. EMERGENCY MANAGEMENT

3.1 PTTEP EMERGENCY AND CRISIS CLASSIFICATION

With reference to the 3-Tier definition of Emergency & Crisis in PTTEP Emergency Crisis Management Standard (SSHE-106-STD-500), emergency covers the situations in tier 1 and tier 2; whereas, a crisis situation is classified as and treated by **a tier 3 response level**.

Tier 1:

- The situation involves a problem, which has limited impact and minimal potential for escalating, poses a threat to the safety & the environment **and poses no threat to the general public**.
- The situation can be handled by the on OSC with the site operation team and/or intervention team within a reasonable timeframe. Tier 1 emergency response can be totally managed by DERTL, being appointed based on the area affected by an incident. After tier 1 emergency situation can be managed and resumed to normal operation, the situation and response details shall be reported to the duty officer and ERTL respectively.

Examples of tier 1 emergency situations in the S1 operation area are, but not limited to, the following.

- Small manageable fires and/or gas leaks, accidents or safety & security threats;
- No hazard to the public in adjacent areas exists;
- Minor injuries may have occurred (treatable through first aid); and
- Danger to the environment is minimal, however, the potential for escalation exists.

Tier 2:

- The situation involves an emergency with greater magnitude and major severity in nature or has the potential to escalate and continue for a significant period of time, or cause a significant impact to public or environment that requires sophisticated implications with external parties.
- The situation involves damage to S1 facilities/assets and/or impact on 3rd parties and may pose a significant threat to safety, environment, and facilities/assets.
- The situation may request external assistance from local authorities in the affected areas i.e. local fire brigade, Sub-district Administrative Office (SAO), local hospital/public health center, Oil Industry Environment Safety Group Association of Thailand (IESG) or the nearby external organizations, and etc.
- The situation may result in the activation of S1 Asset EMT in BKK.

For tier 2 emergency situations, ERT will respond to the emergency site while S1 asset EMT in BKK may be established to manage and provide relevant support to the S1 ERT and/or the affected site.

S1 asset EMT members should include the top management/authorized person of the S1 asset and other key positions from various disciplines that are, but not limited to, the following.

1. EMT Leader – Thai Onshore Asset Senior Vice President (SVP) acts as EMT Leader;
2. Common members such as BKK S1 asset duty, logistic duty, SSHE duty, corporate RRT duty, communication team, IT duty, administration team duty, event logger, etc.
3. Specific members such as drilling duty, construction duty, well operation duty, etc.

Examples of tier 2 emergency situations in S1 operation area are the followings:

- Employees, contractors, service providers, visitors, community, the environment, property, facilities (or any combination of these) are exposed to a significant hazard.
- Non-essential personnel in adjacent areas of S1 operating areas such as LKU flow station, production sub-stations, active well sites, flow lines, BPR depot and etc will need to be evacuated.
- Deaths, and/or multiple serious injuries may have occurred (ambulance and/or medivac may be required).
- There may be significant environmental impacts such as the large volume of hydrocarbon leaks to site surrounding areas.

Tier 3:

- Involves a catastrophic scenario resulted in multiple injuries, fatalities, major fires, environmental damage, toxic gas release, significant business interruption and poses a significant threat to the environment or damage to PTTEP assets and finally brings in significant media attention.
- Requests external assistance from aboard or international resources i.e. the Oil Spill Response Limited Company (OSRL) and the East Asia Response Limited Company (EARL), etc.
- Results in the activation of CMT.

The CMT members consist of the PTTEP top management at the Corporate Level and other supporting functions. Their responsibilities and procedures are defined in the PTTEP CMP (12148-PDR-SSHE-501).

PTTEP Risk Assessment Matrix (RAM) demonstrated in appendix D of PTTEP SSHE risk management standard (11038-STD-SSHE-401) can be used as a guideline to consider the initial appropriate levels of response to any particular event.

3.2 S1 EMERGENCY RESPONSE TEAM ORGANIZATION

S1 production operations are governed by Vice President (VP) of S1 Production Operations Department with a total of six (6) sections of the followings:

1. Production Section (PS1/P);
2. Maintenance Section (PS1/M);
3. Oil Movement and Transportation Section (PS1/O);
4. Production Operations Support Section (PS1/T);
5. Land Acquisition, Permits & Operation Services Section (PS1/L); and
6. Safety, Security, Health, and Environment (SSHE) Section (PS1/S).

Additionally, there are eight (8) support functions providing supports to S1 production operations. These support functions consist of:

1. Public Affairs Section (PTN/A)
2. Operations Training Center Section (HRC/O)
3. Onshore Construction Execution Section (ECM/N)
4. Drilling Operations Section (ETN/D)
5. Well Services Section (ETN/W)
6. Well Services Workshop (ETN)
7. Lan Krabue Support Base Section (PLG/M)
8. Lifting Equipment & Services (PLG/L)

An organigram of S1 production operations is illustrated in **Figure 1**.

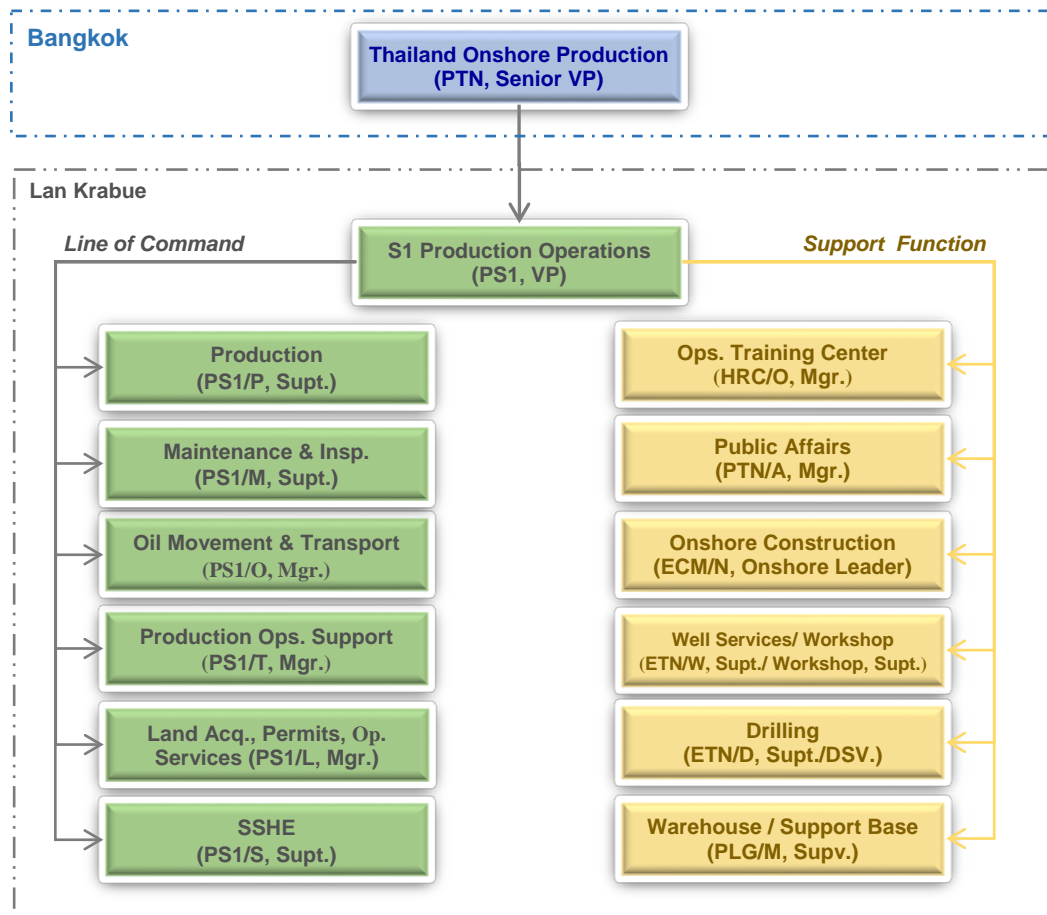


Figure 1: Organigram of S1 production Operations

S1 production operations management team including VP, section heads and representatives from support functions specified in the above organigram is assigned to take roles and responsibilities in ERT depicted in the following paragraphs of this document.

ERT is lead by VP and consists of staff with roles and responsibilities necessary for responding to emergency situations likely to occur in S1 production operations as well as with the conjoined activities e.g. drilling, well workover, project construction, road transport, etc.

ERT assesses the occurring emergency situation & consequences, then determines & prioritize the potential impacts and responsive actions to ensure that emergency operations are conducted in a safe manner while the given emergency situation is sufficiently contained and controlled. To do so, ERT directs, supports and collaborates with the on-scene responsive team, concerned external parties e.g. local authorities, local communities, media, staff's relatives, contractors, customers, etc. In parallel, ERT communicates and collaborates with S1 asset duty person and EMT.

ERT members are:-

1. Emergency Response Team Leader (ERTL) – Vice President of S1 production operations department;
2. Deputy Emergency Response Team Leader (DERTL) – appointed by ERTL, by default the top authority of the area affected by the given emergency situation otherwise specifically appointed by ERTL;
3. Duty Officer – S1 production superintendent otherwise specifically appointed by ERTL;
4. S1 SSHE Advisor – S1 SSHE superintendent or his delegate;
5. Event Logger – S1 production engineer;
6. Muster Logger / Deputy Muster Checker – S1 SSHE officer (operational safety);
7. Muster Checkers – the trained persons assigned to the given muster points;
8. On-scene Commander (OSC) – appointed persons in charge of site location affected by the given emergency situation;
9. Site Operation Team – Normally regular staff who are working at site location;
10. Intervention Team/Firefighting Team – Trained staff who are competent in emergency, fire and rescue operations appointed by ERTL;
11. Medical Team – LKU Doctor/Nurse, Ambulance, and Stretcher Team;
12. LKU Telecommunication Officer (24/7); and
13. On-call Support Team – includes transportation/logistic, drilling, well service, construction, maintenance, IT/Telecom, spill response team, medical response team (CMRT), relative response team (RRT), security, and administration & finance.

The organigram of S1 ERT is illustrated in **Figure 2**.

ERT member assignments for the areas under S1 premise are illustrated in **Table 1 - 5**.

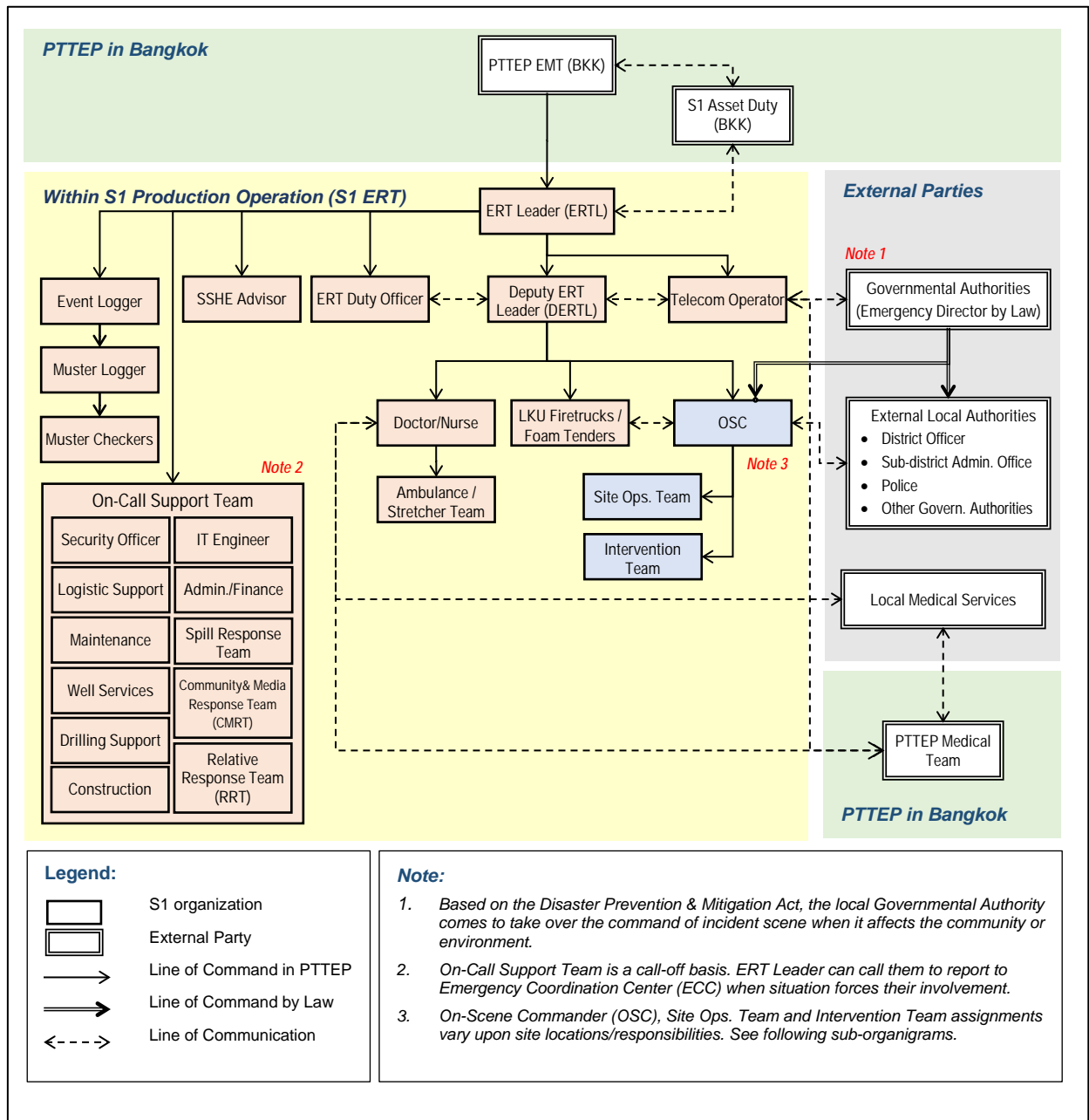


Figure 2: Overall S1 Emergency Response Team Organization

Table 1: ERT Assignment for LKU Flow Station, Workshops and Offices

ERT Assignment for LKU Flow Station, Workshops and Offices		
Role	Assigned to:	Primary Master Point
ERT Leader	VP, S1 Production Operations	ECC
ERT Duty Officer	Production Superintendent	ECC
Deputy ERT Leader	Production Superintendent Workshop Superintendent (Well Service Workshop)	ECC
SSHE Advisor	SSHE Superintendent	ECC
Telecom Operator	On duty telecom Operator	Telecom Room
Event Logger	Production Engineer	ECC
<u>LKU Flow Station and Offices</u>		
On-Scene Commander (OSC)	LKU Plant Supervisor	LKU CCR
Main Muster Logger	SSHE Officer (operation safety)	ECC
Muster Checker 1	Wellsite Supervisor 2	Main Muster Point @ Fire station
Muster Checker 2	Public Affairs Officer	Muster Point #2 @ PNEC Building
Muster Checker 3	LKU Plant Foreman	Muster Point #3 @ LKU CCR
<u>Well Services Workshop</u>		
On-Scene Commander (OSC)	Workshop Supervisor	Well Services Workshop
Area Muster Logger	Workshop Team Leader	Well Services Workshop
Muster Checker	Snr. Tech. (Workshop and General Services)	Muster Point @ In front of the workshop
<u>Material Yard and Material Storage Locations</u>		
On-Scene Commander (OSC)	LKU Support Base Supervisor	Material Yard
Area Muster Logger	Warehouse & Material Yard Team Leader	Material Yard
Muster Checker	Snr. Store Keeper	Muster Point @ In front of the material yard
ERT Assignment Details		
Doctor/Nurse	Doctor/Nurse	Clinic
Ambulance	On duty Ambulance Driver	Clinic
LKU Fire Truck FT01	SSHE Officer (Emergency)	Fire Station
LKU Fire Truck FW01	SSHE Senior Tech. (Emergency)	Fire Station
LKU Foam Tender Truck 1	LKU Depot Operator #1	LKU Depot
LKU Foam Tender Truck 2	LKU Depot Operator #2	LKU Depot
Site Operations Team: <ul style="list-style-type: none"> - Production Supervisor - Power Plant Operator - Panel Operator 	LKU Plant Supervisor Maintenance Power Plant Operator Lead Production Operator (CCR) Senior Production Operator (CCR)	LKU CCR LKU Switchgear Room LKU CCR LKU CCR

ERT Assignment for LKU Flow Station, Workshops and Offices		
Intervention Team: Fire Chief Fireteam Leader 1 - Fireteam 1 member - Fireteam 1 member Fireteam Leader 2 - Fireteam 2 member / Crude/LPG Fire Pump - Fireteam 2 member Fireteam Leader 3 (Backup – F/S) - Fireteam 3 member - Fireteam 3 member Fireteam Leader 4 (Backup – West Well Sites) - Fireteam 4 member - Fireteam 4 member Fireteam Leader 5 (Backup – East Well Sites) - Fireteam 5 member - Fireteam 5 member - Fireteam 5 member	Lead Production Operator (LKU Flow Station) On-duty Production Operator #1 On-duty Production Operator #2 On-duty Production Operator #3 On-duty Production Operator #4 On-duty Production Operator #5 On-duty Lab Technician Off-duty Production Operator #1 Off-duty Production Operator #2 Off-duty Production Operator #2 On-duty Production Operator #1 On-duty Production Operator #2 On-duty Production Operator #3 On-duty Production Operator #1 On-duty Production Operator #2 On-duty Production Operator #3 On-duty Production Operator #4	LKU CCR LKU Flow Station LKU Flow Station LKU Flow Station LKU Flow Station LKU Flow Station LKU Flow Station LKU Accommodation LKU Accommodation LKU Accommodation West Well Sites West Well Sites West Well Sites East Well Sites East Well Sites East Well Sites East Well Sites
On-Call Support Team: - Security Officer - IT Engineer - Logistics Support - Admin./Finance - Construction - Maintenance - Spill Response Team - Community & Media Response Team - Relative Response Team	GGI security Supervisor IT and Telecommunications Supervisor Oil Movement and Transportation Manager Cost Coordination Officer Onshore Execution Team Leader Maintenance Superintendent BRK Intertransport Co., Ltd. Public Affairs Manager Operations Training Center Manager	LKU Gate 1 Officer Main Muster Point @ Fire Station Main Muster Point @ Fire Station Main Muster Point @ Fire Station Main Muster Point @ Fire Station Main Muster Point @ Fire Station BRK Office Main Muster Point @ Fire Station Main Muster Point @ Fire Station

Table 2: ERT Assignment for Well Sites and MPFs (West, East & North)

ERT Assignment for Well Sites and MPFs (West, East & North) including DDC training center		
Role	Assigned to:	Primary Master Point
ERT Leader	VP, S1 Production Operations	ECC
ERT Duty Officer	Production Superintendent	ECC
Deputy ERT Leader	Production Superintendent	ECC
SSHE Advisor	SSHE Superintendent	ECC
Telecom Operator	On duty telecom Operator	Telecom Room
Event Logger	Production Engineer	ECC
Muster Logger	SSHE Officer (operation safety)	ECC
Muster Checker	Assigned Operator	Affected Well Site / MPF
Doctor/Nurse	Doctor/Nurse	Clinic
Ambulance	On duty Ambulance Driver	Clinic
LKU Fire Truck FT01 LKU Fire Truck FW01	SSHE Officer (Emergency) SSHE Senior Tech. (Emergency)	Fire Station
LKU Fire Truck FT02 LKU Fire Truck FW02	Fire Truck Driver (Emergency) Fire Truck Driver (Emergency)	NTM-A
LKU Foam Tender Truck 1 LKU Foam Tender Truck 2	LKU Depot Operator #1 LKU Depot Operator #2	LKU Depot LKU Depot
On-Scene Commander (OSC)	Affected Area Supervisor (Field Supervisors – North, East, West)	LKU Office
Site Operations Team: <ul style="list-style-type: none"> - Production Supervisor - Production Operator - LKU CAO Operator - NTM CCR Operator - STN CCR Operator 	Field Supervisors (North including NTM-A & STN/A, East, West) Affected Area Operators (MPFs) Lead Production Operator (CAO) Production Operator (CAO) Production Operator (NTM-A) Production Operator (STN-A)	LKU Office Affected Well Site / MPF CAO Room NTM-A STN-A
Intervention Team (Well Sites): <ul style="list-style-type: none"> - Fire Chief - Fireteam Leader 1 <ul style="list-style-type: none"> - Fireteam 1 member - Fireteam 1 member - Fireteam Leader 2 (Back-up – Well Sites) <ul style="list-style-type: none"> - Fireteam 2 member - Fireteam 2 member - Fireteam 2 member - Fireteam Leader 3 (Back-up – Well Sites) <ul style="list-style-type: none"> - Fireteam 3 member 	Well Sites in a radius of 30 km from LKU Flow Station including DDC training center Lead Production Operator (Well Sites) On-duty Production Operator #1 On-duty Production Operator #2 On-duty Production Operator #3 On-duty Production Operator #1 On-duty Production Operator #2 On-duty Production Operator #3 On-duty Production Operator #4	Affected Well Sites Affected Well Sites Affected Well Sites Affected Well Sites Other Well Sites Other Well Sites Other Well Sites Other Well Sites Other Well Sites LKU Accommodation

ERT Assignment for Well Sites and MPFs (West, East & North) including DDC training center		
<ul style="list-style-type: none"> - Fireteam 3 member - Fireteam 3 member 	Off-shift duty Production Operator #1 Off-shift duty Production Operator #2 Off-shift duty Production Operator #3 Off-shift duty Production Operator #4	LKU Accommodation LKU Accommodation LKU Accommodation
Intervention Team (NTM-A): <ul style="list-style-type: none"> - Fire Chief - Fireteam Leader 1 <ul style="list-style-type: none"> - Fireteam 1 member - Fireteam 1 member - Fireteam 1 member - Fireteam 1 member - Fireteam 2 member 	Lead Production Operator (NTM-A) On-duty Production Operator #1 Off-shift duty Production Operator #1 Off-shift duty Production Operator #2 Off-shift duty Production Operator #3 Off-shift duty Production Operator #4 Operators assigned to LKU Flow Station, E&W well sites	NTM-A NTM-A NTM-A Accommodation NTM-A Accommodation NTM-A Accommodation NTM-A Accommodation LKU Flow Station, East/West Well Sites
Intervention Team (STN-A): <ul style="list-style-type: none"> - Fire Chief <ul style="list-style-type: none"> - Fireteam 3 member 	On-duty Production Operator #1 Production Operators assigned to NTM-A, east & west well sites	STN-A East/West Well Sites, NTM-A
Intervention Team (MPFs):	Request support by nearby production hub and/or external local authorities	The other production hub
On-Call Support Team: <ul style="list-style-type: none"> - Security Officer - IT Engineer - Logistics Support - Admin./Finance - Construction - Maintenance - Spill Response Team - Community & Media Response Team - Relative Response Team 	GGI security Supervisor IT and Telecommunications Supervisor Oil Movement and Transportation Manager Cost Coordination Officer Onshore Execution Team Leader Maintenance Superintendent BRK Intertransport Co., Ltd. Public Affairs Manager Operations Training Center Manager	LKU Gate 1 Officer Main Muster Point @ Fire Station Main Muster Point @ Fire Station Main Muster Point @ Fire Station Main Muster Point @ Fire Station Main Muster Point @ Fire Station BRK Office Main Muster Point @ Fire Station Main Muster Point @ Fire Station

Table 3: ERT Assignment for Bung Pra (BPR) Depot

ERT Assignment for Bung Pra (BPR) Depot		
Role	Assigned to:	Primary Master Point
ERT Leader	VP, S1 Production Operations	ECC
ERT Duty Officer	Production Superintendent	ECC
Deputy ERT Leader	Oil Movement and Transportation Manager	ECC
SSHE Advisor	SSHE Superintendent	ECC
Telecom Operator	On duty telecom Operator	Telecom Room
Event Logger	Production Engineer	ECC
Main Muster Logger	SSHE Officer (operation safety)	ECC
Affected Area Muster Logger	BPR Depot Operator	BPR Depot
Muster Checker (Road Side)	BPR Depot Senior Security Guard	Muster Point @ In front of T-904
Muster Checker (Rail Side)	BPR Depot Security Guard	Muster Point @ In front of security guardhouse
Doctor/Nurse	Doctor/Nurse	Clinic
Ambulance	On duty Ambulance Driver	Clinic
LKU Fire Truck FT01 LKU Fire Truck FW01	SSHE Officer (Emergency) SSHE Senior Tech. (Emergency)	Fire Station
NTM Fire Truck FT02 NTM Fire Truck FW02	Fire Truck Driver (Emergency) Fire Truck Driver (Emergency)	NTM-A
LKU Foam Tender Truck 1 LKU Foam Tender Truck 2	LKU Depot Operator #1 LKU Depot Operator #2	LKU Depot LKU Depot
On-Scene Commander (OSC)	BPR Depot Supervisor	BPR Depot
Site Operations Team: - Depot Supervisor	BPR Depot Supervisor	BPR Depot
Intervention Team: - Fire Chief - Fireteam Leader 1 - Fireteam 1 member - Fireteam 1 member - Fireteam 1 member - Fireteam 1 member - Fireteam Leader 2 - Fireteam 1 member - Fireteam 1 member - Fireteam 1 member - Fireteam 1 member - Fire Water Pump Operator - First Aider	BPR Depot Operator Rail Side Loader Foreman Rail Side Loader North #1 Rail Side Loader North #2 Rail Side Loader North #3 Rail Side Loader North #4 Rail Side Loader South #1 Rail Side Loader South #2 Rail Side Loader South #3 Rail Side Loader South #4 Road Side Loader Road Side Loader Foreman Tractor Driver	BPR Depot BPR Depot (Rail Side) BPR Depot (Rail Side) BPR Depot (Rail Side) BPR Depot (Rail Side) BPR Depot (Rail Side) BPR Depot (Rail Side) BPR Depot (Rail Side) BPR Depot (Rail Side) BPR Depot (Rail Side) BPR Depot (Rail Side) BPR Depot (Road Side) BPR Depot (Rail Side)
On-Call Support Team: - Security Officer	GGI security Supervisor	LKU Gate 1 Officer

ERT Assignment for Bung Pra (BPR) Depot		
- IT Engineer	IT and Telecommunications Supervisor	Main Muster Point @ Fire Station
- Logistics Support	Oil Movement and Transportation Manager	Main Muster Point @ Fire Station
- Admin./Finance	Cost Coordination Officer	Main Muster Point @ Fire Station
- Construction	Onshore Execution Team Leader	Main Muster Point @ Fire Station
- Maintenance	Maintenance Superintendent	Main Muster Point @ Fire Station
- Spill Response Team	BRK Intertransport Co., Ltd.	BRK Office
- Community & Media Response Team	Public Affairs Manager	Main Muster Point @ Fire Station
- Relative Response Team	Operations Training Center Manager	Main Muster Point @ Fire Station

Table 4: ERT Assignment for CNS Rail Tanker Inspection and Maintenance Workshop

ERT Assignment for CNS Rail Tanker Inspection and Maintenance Workshop		
Role	Assigned to:	Primary Master Point
ERT Leader	VP, S1 Production Operations	ECC
ERT Duty Officer	Production Superintendent	ECC
Deputy ERT Leader	Oil Movement and Transportation Manager	ECC
SSHE Advisor	SSHE Superintendent	ECC
Telecom Operator	On duty telecom Operator	Telecom Room
Event Logger	Production Engineer	ECC
Main Muster Logger	SSHE Officer (operation safety)	ECC
Affected Area Muster Logger	CNS Site Manager (contractor)	CNS
Muster Checker	CNS Safety Officer (contractor)	Muster Point @ In front of security guardhouse
Doctor/Nurse	Doctor/Nurse	-
On-Scene Commander (OSC)	Depot Supervisor (BCP/ TOC/ PTTGC) or CNS Site Manager (contractor)	CNS
Intervention Team	Request support by external local authorities such as BKK metropolitan officer, sub-district office, local medical services, police and/or other government authorities	External local authorities
On-Call Support Team: <ul style="list-style-type: none"> - Security Officer - IT Engineer - Logistics Support - Admin./Finance - Construction - Maintenance - Spill Response Team - Community & Media Response Team - Relative Response Team 	GGI security Supervisor IT and Telecommunications Supervisor Oil Movement and Transportation Manager Cost Coordination Officer Onshore Execution Team Leader Maintenance Superintendent BRK Intertransport Co., Ltd. Public Affairs Manager Operations Training Center Manager	LKU Gate 1 Officer Main Muster Point @ Fire Station Main Muster Point @ Fire Station Main Muster Point @ Fire Station Main Muster Point @ Fire Station Main Muster Point @ Fire Station BRK Office Main Muster Point @ Fire Station Main Muster Point @ Fire Station

Table 5: ERT Assignment for PHS Housing Compounds

ERT Assignment for PHS Housing Compounds		
Role	Assigned to:	Primary Master Point
ERT Leader	VP, S1 Production Operations	ECC
ERT Duty Officer	Production Superintendent	ECC
Deputy ERT Leader	Production Superintendent	ECC
SSHE Advisor	SSHE Superintendent	ECC
Telecom Operator	On duty telecom Operator	Telecom Room
Event Logger	Production Engineer	ECC
Main Muster Logger	SSHE Officer (operation safety)	ECC
Affected Area Muster Logger	Security Guard	PHS Housing Compounds
Muster Checker	Security Guard	Muster Point @ In front of security guardhouse
Doctor/Nurse	Doctor/Nurse	Clinic
Ambulance	On duty Ambulance Driver	Clinic
LKU Fire Truck FT01 LKU Fire Truck FW01	SSHE Officer (Emergency) SSHE Senior Tech. (Emergency)	Fire Station
NTM Fire Truck FT02 NTM Fire Truck FW02	Fire Truck Driver (Emergency) Fire Truck Driver (Emergency)	NTM-A
On-Scene Commander (OSC)	Operation Services Supervisor	LKU office
Intervention Team	Request support by external local authorities such as district officer, -sub-district office, -local medical services, -police and/or -other government authorities	External local authorities
On-Call Support Team: <ul style="list-style-type: none"> - Security Officer - IT Engineer - Logistics Support - Admin./Finance - Construction - Maintenance - Spill Response Team - Community & Media Response Team - Relative Response Team 	GGI security Supervisor IT and Telecommunications Supervisor Oil Movement and Transportation Manager Cost Coordination Officer Onshore Execution Team Leader Maintenance Superintendent BRK Intertransport Co., Ltd. Public Affairs Manager Operations Training Center Manager	LKU Gate 1 Officer Main Muster Point @ Fire Station Main Muster Point @ Fire Station Main Muster Point @ Fire Station Main Muster Point @ Fire Station Main Muster Point @ Fire Station BRK Office Main Muster Point @ Fire Station Main Muster Point @ Fire Station

3.3 ROLES AND RESPONSIBILITIES

This section advises each S1 ERT member of their roles and responsibilities in dealing with emergency situations.

Emergency Response Team Leader (ERTL)	
Responsible Person	Vice President of S1 Production Operations Department
Work Station	S1 LKU Emergency Coordination Centre (ECC) room
Responsibilities	<p>Protect life, environment, plant, production, and reputation by taking effective actions; managing the S1 ERT and collaborating with PTTEP EMT and necessary external parties to ensure the potential for escalation and risk of injury and damage is minimised. S1 ERT leader shall:-</p> <ul style="list-style-type: none"> • Ensure all ERT, CMRT & RRT have received adequate training to cope with their assignments; • Maintain a state of readiness; • Assess the situation; • Take effective actions; • Maintain communication; • Delegate authorities to act; • Manage team performance; and • Deal with stress.
Key Actions	<ul style="list-style-type: none"> • Establish early contact with PTTEP EMT and S1 asset duty persons; • Consider to activate Emergency Coordination Centre (ECC) and call in the ERT members and the On-Call Support Team as deemed necessary. • Manage and coordinate the activities of all S1 ERT members; • Develop an incident response strategy; • Control the incident to prevent escalation; • Maintain communications with PTTEP EMT, SVP of S1 asset, and necessary external parties; • Minimize risk to personnel including intervention team, S1 staff, contractors, and 3rd parties; • Minimize impact on the environment; • Ensure sufficient resources are available to support all response teams; • Plan the delegations of ERT members for rests if the emergency situation has been prolonged; • Plan and prepare for safe evacuation when necessary; • Keep closely informed and monitor the emergency situation, response, and recovery; • Provide any advice and support requested by the operating site;

Emergency Response Team Leader (ERTL)	
	<ul style="list-style-type: none"> • Be a focal point to report and update the emergency situation to BKK S1 Asset Duty by phone as specified in the S1 weekly duty roster or direct report to BKK PTTEP EMT; • Maintain records of events through Event Logger; • Utilise "Time Outs" to update EMT of ongoing situation including: <ul style="list-style-type: none"> - The exact status of the event at the accident scene and evacuation details. - Status and priority of supports provided to the site such as firefighting, medical evacuation, transportation, etc. - Brainstorming and resolving key issues/problems faced. <p>For Tier 2 and 3 other than above:</p> <ul style="list-style-type: none"> • Activate S1 Emergency Coordination Center (ECC) and call in all ERT members and necessary On-Call Support Team. <p>In case of a press release to local media or communities:</p> <ul style="list-style-type: none"> • Call in CMRT to support in dealing with media and community; • Consult with the Crisis Communication Team (CCT) Leader on the general approach to be taken when speaking to the media; • Be a spokesperson for disclosure of information and public statement to local media or communities; • Represent the company externally, in interviews, and at a press conference; • Ensure aid materials (charts, maps, etc) & Technical Advisor are available; • Assess the effectiveness of the press conference with the CCT Leader; and • Log own actions, messages on communication, involved party, and time on the log sheet and pass it to event logger.

ERT Duty Officer	
Responsible Person	The person appointed by ERTL, or by default, the S1 Production Superintendent
Responsibilities	<ul style="list-style-type: none"> • Take a role and responsibility as ERTL until his/her arrival (see ERTL responsibility); and • Keep ERTL informed of the emergency situation, response, and recovery.
Key Actions	<ul style="list-style-type: none"> • Act as ERTL until his/her arrival (see Roles and Responsibilities of ERTL); • Share workloads of ERTL as directed; and • Direct and approve for the mobilization of ambulance, firetrucks, and Spill Response Team.

Deputy Emergency Response Team Leader (DERTL)	
Responsible Person	<p>The person appointed by ERTL based on the area affected by an incident.</p> <ul style="list-style-type: none"> PS1/P for LKU flow station, well sites, MPF locations, workshops, offices, material yard and material storage locations, PHS housing compounds and DDC training center. PS1/O for BPR depot in Phitsanulok Province and CNS rail tanker inspection and maintenance workshop in BKK.
Responsibilities	<ul style="list-style-type: none"> Minimise injury, environmental pollution, asset/property damage and reputation; Assist ERTL to manage and direct actions of the emergency response team, medical team, and incident support function to contain and control the emergency situation; Collaborate with local external parties; and Coordinate with RRT and CMRT when necessary.
Key Actions	<ul style="list-style-type: none"> Update the situation with OSC and assess for the effective response strategy; Provide the resources e.g. manpower, fire/foam trucks, spill response team, financial support, etc. required for the emergency response to OSC, medical team and affected area; Provide technical advice to OSC, ERTL/ERT Duty Officer; Closely report to and take constant directions from ERTL/ERTL Duty Officer for uninterrupted and effective management of the emergency situation. Communicate, directly or through Telecom Operator, with local external parties e.g. governmental authorities, community, etc involving in the emergency situation; Support in collaboration between OSC and external parties; Communicate and collaborate with CMRT and RRT when the situation requires; and Log own actions, messages on communication, involved party, and time on the log sheet and pass it to event logger.

On-scene Commander (OSC) or Deputy OSC		
Responsible Person	The person appointed by DERTL based on the area affected by an incident.	
	Location	OSC
	LKU flow station, workshops, offices	LKU Plant Supervisor
	Well sites and MPFs including DDC training center	Affected Area Supervisors (Field Supervisors – West, East & North)
	Well services workshop	Workshop Supervisor
	Material yard and material storage locations	LKU Support Base Supervisor
	BPR Depot	BPR Depot Supervisor
	CNS rail tanker inspection and maintenance workshop	Depot Supervisor (BCP/ TOC/ PTTGC) or CNS Site Manager (contractor)
	PHS housing compounds	Operation Services Supervisor
Responsibilities	<ul style="list-style-type: none"> • Protect personnel including staff, contractors, community, intervention & medical teams; • Minimise the impact to environment and community in the vicinity; • Assess the situation and establish the tactical response; • Take commands of all immediate responsive activities on the incident scene; • Report to and provide constant updates of the situation to DERTL; • Collaborate with involving local authorities; and • Maintain records of events. 	
Key Actions	<ul style="list-style-type: none"> • Assess the current emergency situation, associated hazards, impacts, and their potentials; • Establish tactical response plan e.g. isolation, blowdown, spill containment, evacuation, intervention, etc; • Command the site operation, intervention & medical teams on the scene; • Provide necessary resources to site operation, intervention and medical teams; 	

On-scene Commander (OSC) or Deputy OSC	
	<ul style="list-style-type: none"> • Ensure all personnel are adequately protected against arising hazards, especially site operation and intervention teams; • Regularly call “time out” to update and assess the current status of the situation and changes, then direct site operation, intervention, & medical teams as appropriate; • Initiate site evacuation if necessary; • Provides necessary initial information to immediate local authority e.g. SAO, police, hospital, etc; • In consultation with PTN/A (public affairs), assess the impacts and inform the nearby community as necessary; • In consultation with DERTL, consider community evacuation if situation deemed dangerous or has potential to cause danger; • Plan the staff change over for site operation, intervention and medical teams if the situation is prolonged; • Keep DERTL updated with situation, changes, progress, and potentials; and • Log own actions, messages on communication, involved party, and time on the log sheet and pass it to event logger. <p>According to the “Disaster Prevention and Mitigation Act”, when emergency situation poses or has potential to pose the significant danger to community and environment, the governmental authority of the affected area will overtake the command of overall emergency response as “Emergency Director”.</p> <ul style="list-style-type: none"> • When a situation deemed as in the above condition, provides initial information on the emergency situation to the local authority; • When local authority comes to take over the command, report to Emergency Director, and in parallel collaborate with ERT for effective emergency response and recovery; and • Provide necessary technical advice to the Emergency Director and teams.

Site Operation Team	
Responsible Person	The staff assigned by OSC to operate and/or control the affected facility and area. In an emergency, they assist OSC to recover or make safe the facility and area by operating the facility, isolating & removing the arising hazards and providing necessary supports to the intervention team to contain the situation.
Responsibilities	<ul style="list-style-type: none"> • Be under command of the OSC; • Operate/control/stabilize the affected facility and area; and • Support the intervention and medical teams.
Key Actions	<ul style="list-style-type: none"> • Provide detailed current status of facility and area to the OSC e.g. process & area condition, process safety system, F&G system, firefighting system, etc; • Control and stabilize the facility and area e.g. shutdown, isolation, blowdown, inhibit/override of system, removal of hazards, etc; • Maintain safe conditions of facilities and area throughout emergency situation; • Notify hazards associated with process, facility, and area to OSC and intervention team; • Keep OSC updated with changes in conditions of the process, facilities, and area; and • Log own actions, messages on communication, involved party, and time on the log sheet and pass it to event logger as applicable.

Intervention Team Leader (ITL)	
Responsible Person	The person assigned to lead the intervention team and direct tactical intervention activities e.g. firefighting, rescue, recovery of distressed personnel, etc.
Responsibilities	<ul style="list-style-type: none"> • Provide a frontline response to the incident scene as directed by OSC; • Lead intervention team in coordination with site operation and medical teams.
Key Actions	<ul style="list-style-type: none"> • Update the status of situation and potential with OSC and intervention team; • Take priority on the safety of the intervention team and others; • Consider the hazards and potentials of a gas cloud, oil spill, fire, boil over, BLEVE, collapse of structure & vessel, traffic, etc.; • Size up the situation and establish tactical frontline action plan; • Utilize automatic system e.g. fire pumps, monitor, deluge, etc. • Ensure adequate and effective communication amongst the intervention team and with others; • Establish the forward control point for intervention and medical teams as necessary; • Collaborate with other supporting teams e.g. site operation & medical team, and others e.g. fire brigade, police, etc.; • Brief the intervention team on the situation, potentials, target of achievement, and tactical action plan; • Direct the intervention team to accomplish the tactical action plan; • Monitor closely the intervention actions and assess the result. The intervention action plan may change upon the upcoming changes with the situation; • Make regular contact with the intervention team and OSC for updates and changes; and • Request external supports and resources when necessary.

Intervention / Fire Team Member	
Responsible Person	The persons assigned as an intervention team member shall be adequately trained and competent to conduct the hand-on intervention activities e.g. firefighting, rescue, oil spill response, etc.
Responsibilities	<ul style="list-style-type: none"> • Ensure the safety of own and others; • Under command of ITL • Provide frontline responsive actions on the emergency situation as directed.
Key Actions	<ul style="list-style-type: none"> • Wear adequate and proper PPE to conduct the assigned task e.g. firefighting, rescue, chemical intervention, oil spill, etc.; • Receive a briefing on the situation, hazards, preventive measures and responsive action plan from ITL; • Conduct the actions assigned by ITL in a safe manner that may involve: <ul style="list-style-type: none"> - Reconnaissance of incident scene; - Operating the automatic firefighting device; - Conducting firefighting task; - Conducting rescue, extraction, recovery, and handling of casualties; and - Assisting in control of traffic and access.

Medical Team	
Responsible Person	Medical Team consists of <ol style="list-style-type: none"> 1. LKU Doctor/Nurse 2. Ambulance Driver 3. Off-shift Duty Ambulance Driver 4. Stretcher Team
Responsibilities	<ul style="list-style-type: none"> • Safety of own and others; • Size up the situation and activate the appropriate medical procedure; • Stabilize the casualties and initiate the transfer of casualty to hospital/medical centre in a safe manner as necessary; • Assess the extents of injuries and provide advice to the DERTL and/or OSC for appropriate treatment and further supports and resources required; • Assist in arranging medical evacuation/referral; • Coordinate with the PTTEP medical team and casualty-receiving hospitals; and • Log all actions, communication made, detail & number of injury, time, etc. on the log sheet.

Medical Team	
Key Actions	<p>LKU Nurse</p> <ul style="list-style-type: none"> • Make ready, at all times, the medical equipment, and supplies at the clinic, in portable packs, and on the ambulance required for emergency response; • Size up the situation and take appropriate actions and give adequate first aid/initial medical treatment; • Utilize the available supporting staff in casualty handling e.g. intervention team, stretcher team, etc.; • For multiple casualties, consider to activate triage procedure and request for support from the selected hospital and medical service centre; • Seek advice from PTTEP medical team when necessary; • Assess and advise on the appropriate medical evacuation/referral to OSC and/or DERTL; • Coordinate with PTTEP medical team and hospital receiving the casualty to ensure the appropriate treatment and followup; and • Keep records of casualties and treatments. <p>On-Duty Ambulance Driver</p> <ul style="list-style-type: none"> • Have undergone the defensive driving and advanced first aid training courses; • Have ensured the ambulance is in ready & clean condition with adequate fuel (minimum half a tank); • Get familiarized with the routes for transport; • Drive the ambulance in a safe manner based on defensive driving principle; • Assist the handling of casualties under supervision of doctor/nurse; and • Make entries into a driving log. This information includes injured persons'/ patients' names and addresses, trip times, mileage, and services performed. <p>Off-Duty Ambulance Driver</p> <ul style="list-style-type: none"> • Assist doctor/nurse to provide first aid treatment and handling of casualties. <p>Stretcher Team</p> <ul style="list-style-type: none"> • Assist medical team in manual transfer of casualty. <p>Remark: In case of PTTEP ambulance absence, a back-up van having medical equipment as equal to the ambulance should be available.</p>

SSHE Advisor	
Responsible Person	Superintendent, SSHE of S1 Asset or his delegation
Responsibilities	<ul style="list-style-type: none"> • Advise ERTL, DERTL, ERT duty officer, OSC, etc on SSHE matters and procedures relevant to emergency response & management; • Observe the situation, taken actions, deficiencies, gaps for improvement, and advise ERTL & ERT duty officer; • Ensure the procedure and actual practice are consistent and appropriate to regulations; and • Collect all information for the summary report to be further issued.
Key Actions	<ul style="list-style-type: none"> • Evaluate the hazards and potentials of the incident and impacts; • Provide necessary information to ERTL, ERT duty officer and other members in ECC room; • Observe the ERP, relevant legislations, and the actual actions taken along with the emergency response process, then identify discrepant and deficiency and inform ERTL and/or DERTL; • Take note of all observations; • Support and liaise with event logger to ensure all necessary information and correct timeline are logged; • Ensure personnel accountability including those deployed to the emergency scene; • Provide technical advice on equipment, resources, and method to control, contain, and prevent the emergency situation, escalation & impact; • Communicate with and seek advice from corporate SSHE division as necessary; • Call in other members of S1 SSHE staff to support as necessary; • After the emergency is over, collect all information, papers, photographs, other evidence of the emergency and response process. Compile a summary report for Vice president of S1 production operations department; and • Log own actions, messages on communication, involved party, and time on the log sheet and pass it to event logger.

Telecom Officer	
Responsible Person	Telecommunication Operator
Responsibilities	<ul style="list-style-type: none"> Be available, at all times, to receive an emergency call; Make accurate communication with internal and external parties as specified in ERP and instructed by ERTL; and Record details of all calls made in and out with the timeline.
Key Actions	<ul style="list-style-type: none"> Maintain up-to-date emergency contact numbers for all internal and external parties; Make weekly call tests with S1 duty roster numbers; Ensure all telecommunication equipment in telecommunication room is readily available at all times; Upon receiving the emergency information, immediately report to ERT duty officer, ERTL, OSC, SSHE duty respectively; Upon confirmation from ERTL or ERT duty officer, report to EMT duty person; Upon request from ERTL or ERT duty officer, call in ERT members to report to ECC room; Support ERT in making calls to internal and external parties; and Log details of calls received and made on the log sheet.

Event Logger	
Responsible Person	S1 Production Engineer
Responsibilities	<ul style="list-style-type: none"> Log details of the situations and actions on the event log boards/sheets; and Ensure the logged information logged are accurate and adequate with what, when, where, who, whom & how questions principle.
Key Actions	<ul style="list-style-type: none"> Liaise with all ERT members to obtain significant and accurate information; Observe and listen to the communication made in ECC and take necessary information; Avoid interrupting ERT members when they are occupied with work; Log the received information in the chronological order on the event log boards/sheets in an accurate and clear manner; Update the status board e.g. mustering, mobilization of firetrucks & other resources, etc.; Maintain the trailing records and update the current information of the situation; and Assist ERTL or ERT duty officer to feed necessary information in "time out".

Muster Logger / Deputy Muster Checker	
Responsible Person	S1 SSHE Officer (Operational Safety)
Responsibilities	<ul style="list-style-type: none"> Obtain and consolidate the personnel counts from each muster point (muster checkers); Communicate with muster points; Monitor and record the movements of personnel when called for duty;
Key Actions	<ul style="list-style-type: none"> Communicate with all muster checkers to obtain personnel counts; Together with muster checkers, identify the missing person; Update status of personnel counts to event logger; Coordinate with muster checkers for evacuations; Log own actions, messages on communication, involved party, and time on the log sheet and pass it to event logger; and Assist event logger for event logs.

Muster Checker	
Responsible Person	Persons appointed to responsible muster points
Responsibilities	<ul style="list-style-type: none"> Personnel counts at the designated muster point; Identifying missing person; Ensure safety and order of personnel at the muster point to be in order; Control and lead the evacuation of the designated muster point; and Communicate with a muster logger.
Key Actions	<ul style="list-style-type: none"> Ensure the mustered personnel are safe and remain in order; If the designated muster point is not safe, coordinate with muster logger for alternative muster point; Take a headcount of personnel at the designated muster point and report the result to muster logger; Identify the missing person with muster logger; Observe the mustered personnel for illness or injury and provide necessary supports; Coordinate with muster logger for personnel called from muster point for duty during an emergency; Encourage mustered personnel to calm down and be positive; Release persons for specific duty as requested by ER Team Leader and Muster Logger informed of this update/change; and

Muster Checker

	<ul style="list-style-type: none"> Ensure all personnel remains at muster point during an emergency, it is not safe or receives instruction from ERTL, ERT duty officer or DERTL.
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Fire Warden (Building)

Responsible Person	Persons working in building assigned to take the role of fire warden.
Responsibilities	In evacuation, ensure all personnel leaves area in a safe manner to muster points
Key Actions	<ul style="list-style-type: none"> Direct all personnel in the designated area to leave the area for musters in a safe manner using appropriate routes and exits; Assist handicaps e.g. elderlies, children, injured, pregnant, disable, etc. Check all accessible spaces in their area, including the bathroom, store, pantry, etc, to make sure everyone has evacuated – this should be done on the way out of the building so that the fire warden does not put himself/herself at risk by re-entering the evacuated area; Close doors to help suppress or hinder the fire; Guide personnel to the muster points and assist in checking personnel having arrived safely at muster points; and Update with the list of staff stationed in the building given by PS1/S (emergency team).

On-Call Support Team	
Responsible Person	The persons selected are the representatives of each discipline to support ERT when needed.
Responsibilities	<p>The On-Call Support Team comprises of representatives from a number of various disciplines. They are specialized and act as advisors and communication links.</p> <p>The On-Call Support Team consists but not limited to the following members:</p> <ul style="list-style-type: none"> <input type="checkbox"/> Logistic Support; <input type="checkbox"/> Well Service; <input type="checkbox"/> Maintenance; <input type="checkbox"/> Security Supervisor; <input type="checkbox"/> Community & Media Response Team; <input type="checkbox"/> Relative Response Team. <input type="checkbox"/> Drilling; <input type="checkbox"/> Construction; <input type="checkbox"/> IT/ Telecom Supervisor; <input type="checkbox"/> Spill Response Team;
Key Actions	<ul style="list-style-type: none"> • Be ready on call, able to report to ECC within 2 hours when called by ERTL or ERT duty officer; • Be the link of communication between ERT and their assigned sections, departments, contractors; • Advise ERT on their specialized matters; • Collaborate with the assigned discipline on request; • Execute the task to support emergency response requested by ERT; • Receive briefing from ERTL or delegation; • Advise ERT members on matters relating to their discipline matters; • Call in or consult with other staff in their disciplines as required; • Provide support to ERT members as required; and • Log own actions, messages on communication, involved party and time on the log sheet and pass it to event logger.

Community & Media Response Team (CMRT)	
Responsible Person	Manager, Public Affairs Section and Team
Responsibilities	<p>Act as a point of contact and advise on all press related issues in supporting ERTL for appropriate communication with media and community.</p> <p>Note: Mobilize the team to Communication & Media Response Room (CMRR) at LKU Building #1 Room #2 when Tier 2 and 3 emergency level is activated.</p>
Key Actions	<ul style="list-style-type: none"> • Establish a proactive media liaison and public affairs strategy; • Seek advice, work closely and maintain communication with PTTEP Crisis Communication Team (CCT) for information review prior to delivering a response to local media and community; • Brief ERTL on local media interest, issues developing and requests from the media for information; • Assist in developing/delivering a response to the local media and community as directed by ERTL; • Maintain a log of media activity identifying the line of questioning being adopted by the media and issues developing and pass this information to ERTL; • Maintain a personal log of events undertaken during the incident life cycle and pass completed log sheets to Event Logger; • Ensure that Event Logger has a record of all contact with authorities; • Establish contact numbers where the media can call for information; • Pass any press releases to ERTL for approval process; • Update ERTL on all media and external affairs issues; • Monitor media related to an emergency; and • Liaise with ERTL if there is a requirement to confront any press interviews/conference.

Relative Response Team (RRT)	
Responsible Person	Manager, Operations Training Center Section and Team
Responsibilities	<p>Act as a point of contact and advise on all human resources related issues.</p> <p>Provide support for human resource issues handling.</p> <p>Note: Mobilize the team to Relative Response Room (RRR) at LKU Building #2 Meeting Room when Tier 2 and 3 emergency level is activated.</p>
Key Actions	<ul style="list-style-type: none"> • Have information on staff's selected relative's contact number for emergency; • Seek advice, work closely and maintain communication with PTTEP HR department for the information on the status of staff injuries, company welfare, legal concerns, and additional support required; • Advise ERTL on personnel and welfare issues relating to staff. • Hold the information on the status of ERT members, staff and contractors affected by the incident and emergency e.g. injured, deceased, locations, etc. • Coordinate with PTTEP HHR (Human resources) division; • Coordinate with hospitals for treatment of injured persons and provide the additional support required; • Consider mobilising RRT to interface with family or relatives of the impacted staff; • Make a note and maintain a personal log of all relevant information received and the consequential activity performed and pass each note to Event Logger; • Assist the Event Logger in tracking personnel on the status boards and ensure accuracy of information; and • Establish the requirement for counselling services for those affected by the emergency (open to all employees and contractors).

Each ERT member shall record the details of message/events upon receiving in to the emergency log sheet form (**Appendix C**).

3.4 EMERGENCY RESPONSE ACTION

The response action of an emergency situation occurring at S1 operating sites can be summarized in flowing details.

1. When an emergency occurs, OSC with the site operation team and intervention team responds to the emergency situation as soon as possible.
2. OSC will evaluate the tier of emergency in consultation with the ERT duty officer.
 - a. Even though the emergency situation is within tier 1, localized and can be handled by site staff (OSC, site operation, intervention, and medical team), yet OSC shall immediately report to ERT duty officer for further justification;
 - b. If the emergency falls into tier 2,
 - i. Upon receiving the emergency information, ERTL or ERT duty officer shall activate ERT and ECC room. LKU telecom officer shall immediately call the duty persons of S1 ERT (see Section 3.2) to meet together at the S1 ECC room.
 - ii. ERTL or ERT duty officer shall lead ERT, in responding to the emergency situation.
 - iii. ERTL or ERT duty officer shall immediately contact BKK S1 asset duty and/or EMT Leader (SVP.). EMT will be established to manage and provide relevant supports to the asset in the tier 2 emergency situation.
 - iv. ERTL or ERT duty officer reported the emergency situation to the local governmental authority of the affected area.
 - v. DERTL or OSC may establish direct contacts for supports with external parties in the area e.g. SAO, police, hospital, medical service centers, provincial electricity authority, etc.
 - vi. The affected local government authority takeovers the emergency management by acting as Emergency Director (ED) if the emergency significantly affects the community or environment according to the Disaster Prevention and Mitigation Act.
 - vii. Even though OSC takes the command from ED, OSC yet carries on with emergency response on the scene in an effective way. The ED could be the executive chief of affected SAO or higher.
 - viii. OSC, while taking command from ED, collaborates with ERT for supports and information updates.
 - c. If the emergency escalates to tier 3, the situation goes beyond the capability of EMT, ERT & OSC to handle, the CMT shall be established in BKK. Emergency response and management shall be conducted according to PTTEP Emergency and Crisis Management Standard (SSHE-106-STD-500) and Crisis Management Plan (SSHE-106-PDR-501).

In case of emergency with S1 external organization in S1, but not directly under responsibility of S1 production operations department (PS1), e.g. new drilling site, new construction site, seismic survey, etc., the Company Site Representative (CSR) shall act as OSC for their responsible location and report directly to S1 DERTL.

Apart from the normal function line reporting procedure, CSR as OSC shall report all incidents to S1 telecom officer and ERT duty officer.

The Emergency Tier Evaluation & Response Flowchart is shown in **Figure 3**.

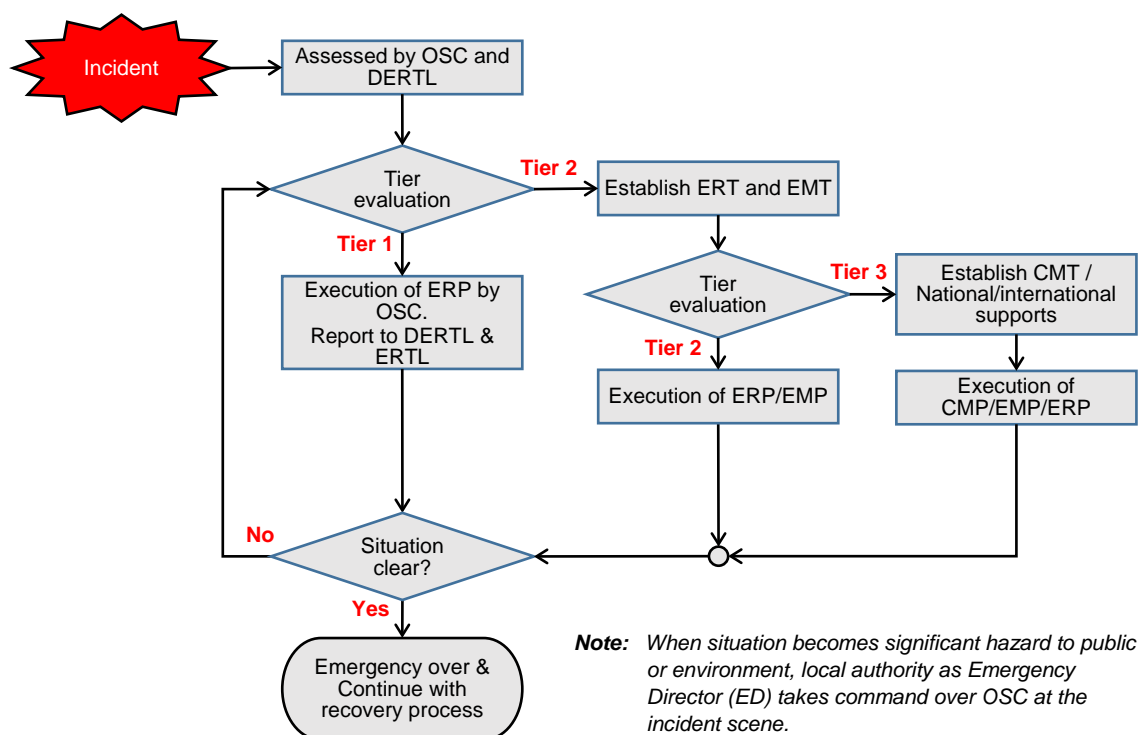


Figure 3: Emergency Tier Evaluation & Response Flowchart

3.5 COMMUNICATION DURING EMERGENCY

During an emergency, communications can be executed by the following methods.

- Radio;
- Landline Telephone;
- Mobile Phone;
- E-mail; or
- Fax

Portable radios (VHF) are provided to S1 operational staff and assigned as the primary option for emergency communication. In normal situations, all handheld radio users are on channel 15. In emergency situations, telecom operator broadcasts to all stations involving an emergency e.g. ERT, OSC, affected site operation, intervention & medical teams to switch to channel 16 for emergency communication. Others not related to emergency may remain on channel 15 for their normal operational communication.

Besides, the external and internal telephone numbers are provided to support both normal and emergency communication. The S1 emergency numbers (external: 055 731 150, internal: 33) are provided at the telecom room which is manned 24 hours every day for all emergency calls from S1 internal and from external parties e.g. community, governmental bodies, etc. Telecom operator is responsible to respond to all calls, take & log precise messages on the given log sheet and relay it to responsible persons (see roles and responsibilities of telecom operator in section 3.3).

The formal emergency call messages that need to be informed to Emergency Response Team, on-call support team and involved parties by LKU Telecom. Operator are shown in **Appendix A**. The emergency report form which will be logged by LKU Telecom. Operator on receiving notification of emergency is illustrated in **Appendix B**.

Email; LKUtelexRoom@pttep.com and fax; 02 537 6212 are available to support informative communication e.g. text, photographs, etc.

Most of the emergency cases, they begin with the incidents then escalate into an emergency. Therefore, the appropriate and timely notification of incidents can improve the responsive actions to the incident and attenuate the situation not to become an emergency. The initial emergency communication flow is illustrated in **Figure 4**.

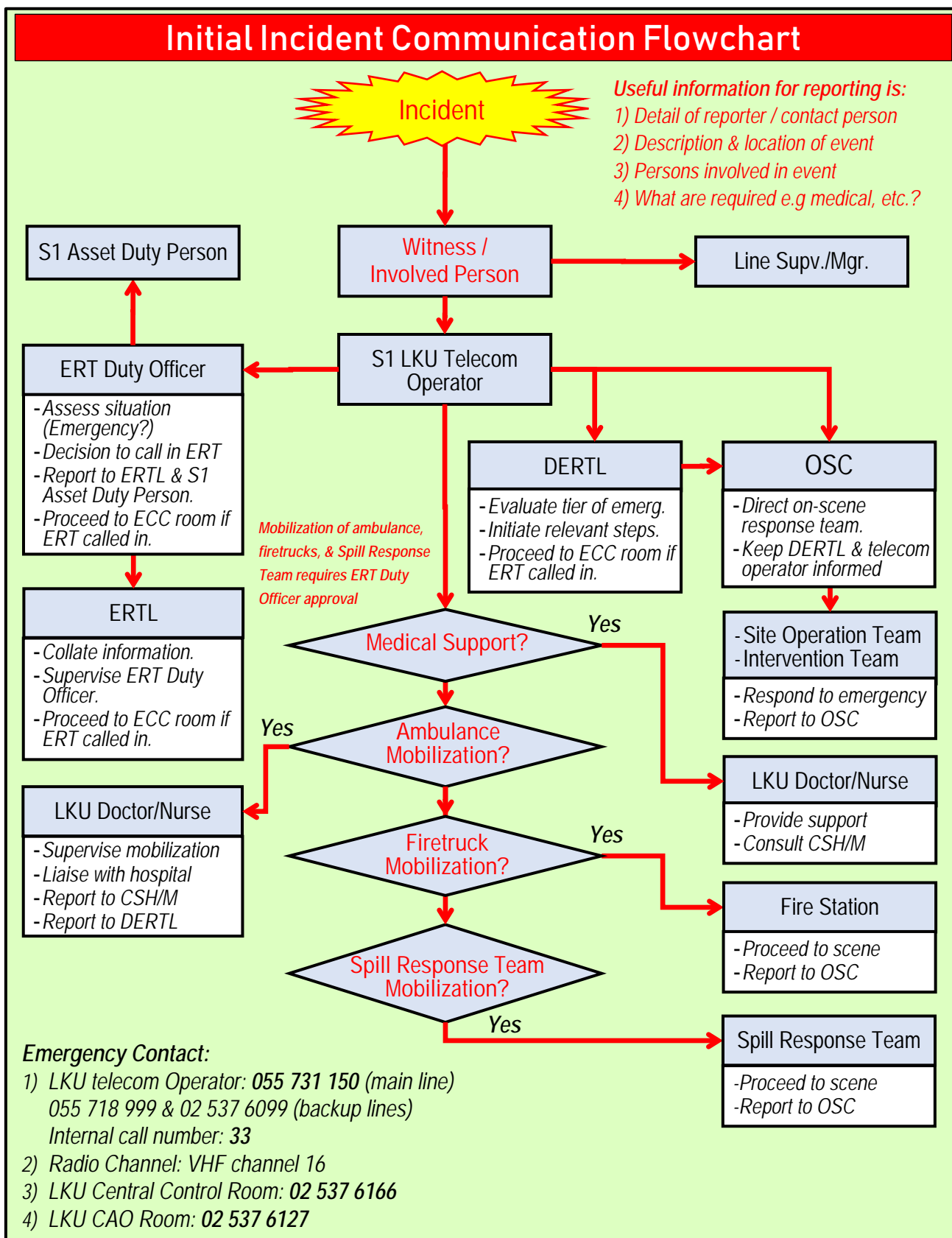


Figure 4: S1 Initial Incident Communication Flowchart

3.6 MUSTER POINT

The muster point is the predetermined place where is at a safe distance from the potential hazards and with adequate space for gathering and counting personnel in an emergency situation.

3.6.1 Type of Muster Point

a) Primary Muster Point

The primary muster points are for personnel to take an initial assembly when the emergency situation requests to muster e.g. LKU CCR is a primary muster point for flow station operation & intervention teams, ECC room is a primary muster point for ERT, area behind fire station is a primary point for all personnel not involving the emergency response actions. The assigned muster checker (and backup muster checker) shall be present to keep muster in order, for personnel movement control, for personnel counts, and for communication with muster logger.

b) Backup Muster Point

The backup muster point is the secondary muster point where personnel gathers in case they cannot safely proceed to the primary muster points. The backup muster point is not always necessary for all locations if alternative escape routes to primary muster point can be assured.

Depending on emergency situation, the predetermined muster points of all S1 locations are displayed in **Appendix D**.

3.6.2 Mustering Action

All personnel at S1 shall be briefed on their designated muster point and action to take at muster point that shall include, but not limited to:

For all personnel:

- On hearing/knowning mustering alarm or notification, make worksite safe proceed to the designated muster point. Walk fast and do not run;
- Observe the safety of the passage. Take the fastest route to proceed to the designated primary muster point. If it is not safe, take an alternative route;
- If there is no safe alternative route, proceed to the predetermined backup muster point, call S1 emergency number 055 731 150 or radio VHF channel 15, and standby for instruction; and
- At the primary muster point, stay calm and keep noise low. Respond to the muster checker and report any information necessary to emergency handling.

Note: Security guards on duty at all gates remain at gates and support access control during emergency otherwise it is not safe to do so.

For muster checker:

- At the muster point, stay calm and take control of the muster;
- Initiate the predetermined personnel count procedure;
- Observe and provide support to the mustered persons e.g. injury, fear, panic, etc.;
- Report the number of mustered persons, missing persons, injury, etc. to the muster logger when requested;
- Maintain muster in order and ensure the comfort of mustered persons as practical. No person should leave the muster point without instruction from ERT. Take record of mustered person movement when called out by ERT;
- When the muster point is deemed unsafe, consult the muster logger to move the muster point to the safe place as practical; and
- Only when the muster logger instructs, release the mustering.

The locations of predetermined muster points, positions of Muster Checker and Muster logger of each S1 operating location are summarized in **Appendix D**.

3.7 FACILITIES

The facilities shall be provided to support activities by the OSC team, ERT, CMRT, and RRT. These facilities shall be adequately equipped for the effective performance of the designed team, especially for communication and information management. All ICT equipment in those rooms shall be well maintained and checked by PS1/M (ICT) to ensure all ICT equipment is always readily available and fully functioning. All materials and documents in those rooms are prepared and made ready for prompt use by the PS1/S section.

At LKU office, 4 separate rooms are provided for:-

1. Emergency Coordination Centre (ECC) room for ERT to occupy for their duties;
2. Relative Response Room (RRR) for RRT to occupy for their duties;
3. Communication and Media Response Room (MRR) for CMRT to occupy for their duties;
and
4. Press Release Room (PRR) for the press release and media interfaces.

Other than the aforementioned rooms, the LKU CCR and CAO rooms are to be ready with ICT, materials, and documents ready for emergency response as well. PS1/P section is in charge of ensuring they are readily available.

3.7.1 Emergency Coordination Centre (ECC)

ECC is located at LKU building #1 meeting room #1. The ECC is arranged for S1 ERT and on-call support team to gather and use for their emergency duties.

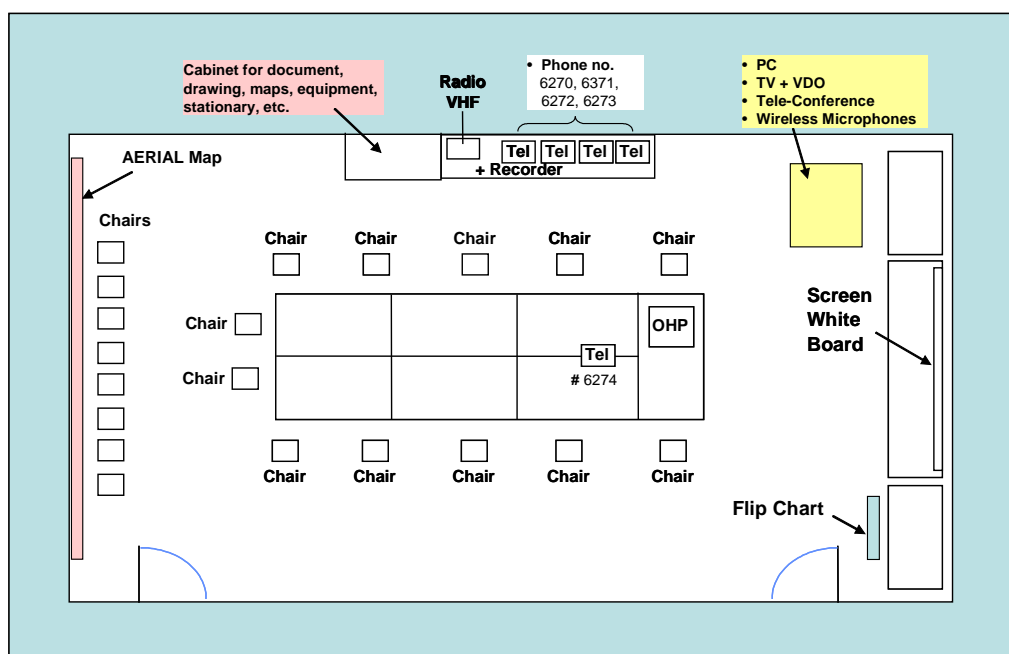


Figure 5: Simplified Layout of Emergency Control Room

Emergency Coordination Centre (ECC) – First In Actions

- Shift the magnet bar for register/muster;
- Switch on and ensure that the PC is working correctly;
- Lower the projection screen and turn on the digital projector;
- Log on the main PC using appropriate user name & password (kept in the cupboard);
- Check that all telephones are working correctly;
- Checks all required documents are available and updated (tel. directory, duty roster list, drawings, etc.);
- Take the briefing from ERTL or ERT duty officer and refer to individual role checklists.

ECC Equipment List

Telephones:	5 PABX telephone extensions {810-6270, 6272, 6273, 6274, 6371}
Display boards:	Casualties' status, the sequence of events, POB status, weather condition, and status of emergency resources.
Information Board:	1 board showing POB information, authorised delegates, Duty Rosters, stationery and forms
Documentation:	<ol style="list-style-type: none"> 1. Corporate Emergency Management Plan 2. Corporate Crisis Management Plan 3. S1 Emergency Response Plan 4. Key Site Drawings of Facilities and Installations 5. Emergency Log Sheets 6. Telephone directory 7. S1 Emergency Reporting Flowchart 8. S1 Duty Roster List

In case the ECC room at LKU building #1 meeting room #1 cannot be utilized when an emergency occurs such as fire or bomb threat at the office building, flooding, road blockage, the predetermined alternative venues are:

1. The meeting room at well services workshop; and
2. PHS housing.

Upon such a situation, ERTL or ERT duty officer announces to all ERT members to report to an alternative ECC room.

3.7.2 Community and Media Response Room (CMRR)

CMRR is located at LKU Building #1 Room #2 for CMRT to utilize for their emergency duties e.g. information preparation, press compilation, communication, etc. S1 Public Affairs (PTN/A) staff take roles and responsibilities as CMRT.

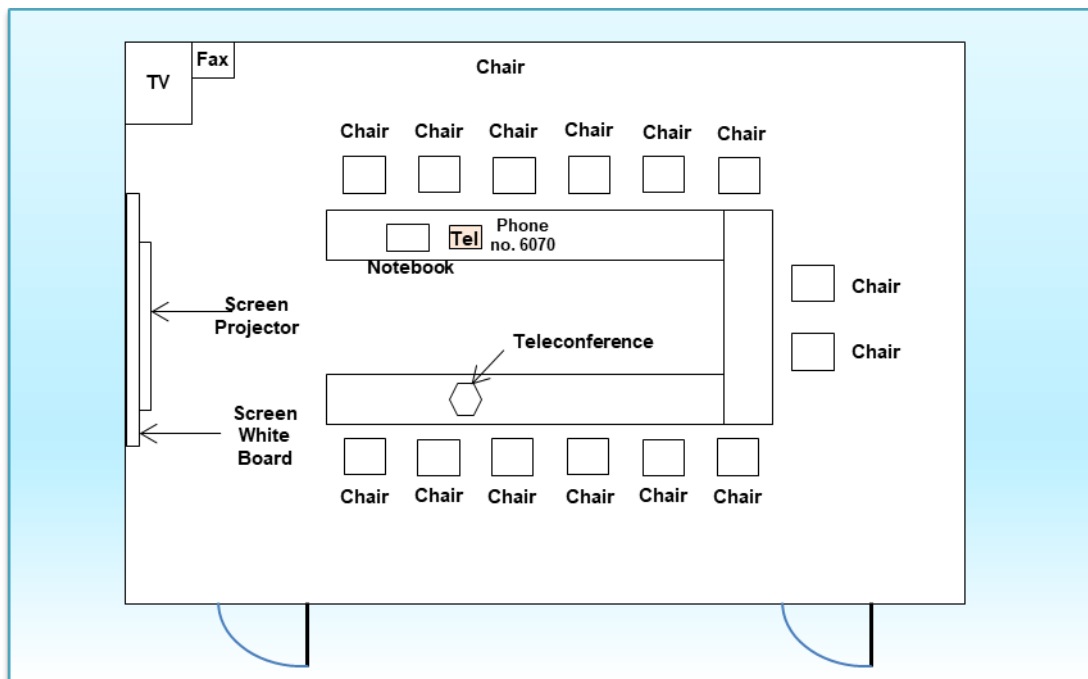


Figure 6: Simplified Layout of Media Response Room (MRR)

Community and Media Response Room (CMRR) – First In Actions

- Ensure that the PC is working correctly;
- Log on the main PC using appropriate user name & password (kept in the cupboard);
- Ensure all required document e.g. emergency contact list, community contact list, etc. are available;
- Check that all telephones are working correctly;
- Await the briefing from Manager, Public Affairs Section.

CMRR Equipment List

- Telephones:** 1 PABX telephone extensions No. 810-6070
- Information Board:** 1 board for preparation on the media press release
- Documentation:**
1. S1 Emergency Response Plan
 2. List of local media with telephone directory
 3. List of Corporate Community & Media Response Team with telephone directory
 4. S1 Emergency Reporting Flowchart
 5. S1 Duty Roster List

3.7.3 Relative Response Room (RRR)

Relative Response Room (RRR) is located at LKU Building #2 Meeting Room. RRR is arranged for the Relative Response Team (RRT) for preparation on information and coordination with relatives of staff and contractors who are injured or deceased. Operations Training Center (HRC/O) staff take roles and responsibilities as RRT.

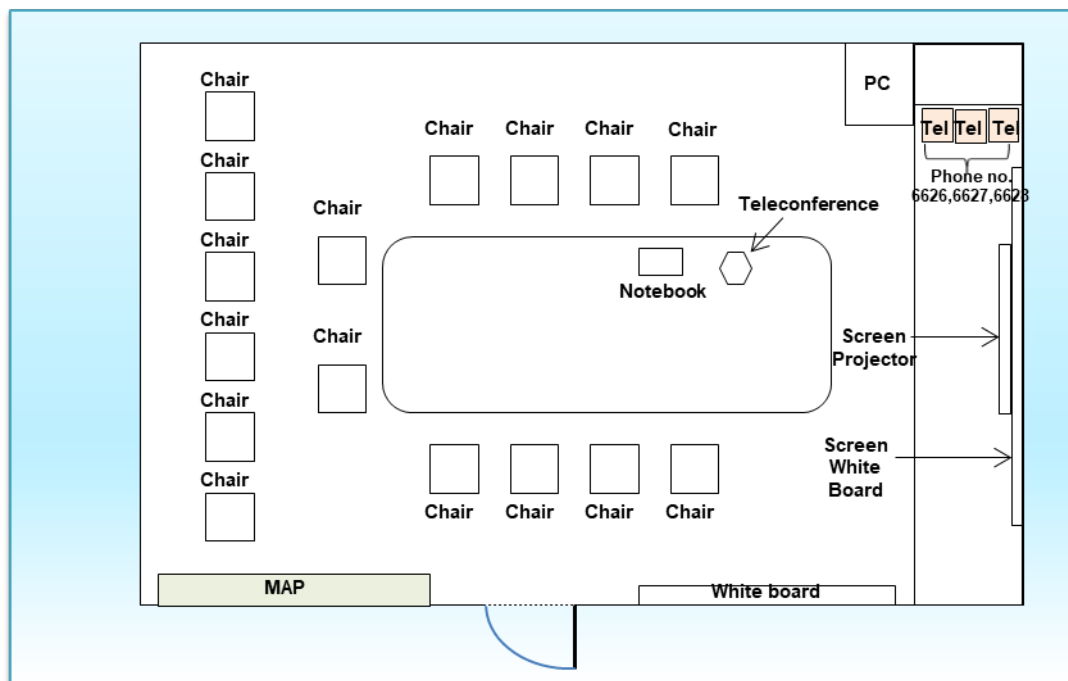


Figure 7: Simplified Layout of Relative Response Room (RRR)

Relative Response Room (RRR) – First In Actions

- Ensure that the PC is working correctly;
- Ensure accessibility to staff database and contract holder list;
- Log on the main PC using appropriate user name & password (kept in cupboard);
- Check that all telephones are working correctly;
- Await the briefing from manager, Operations Training Center Section

RRR Equipment List

- Telephones:** 3 PABX telephone extensions {810-6626, 6627, 6628}
- Information Board:** Staff and contractor status board
- Documentation:**
1. S1 Emergency Response Plan
 2. List of focal point of S1 department staff and contractors with telephone directory
 3. List of Corporate Relative Response Team with telephone directory
 4. S1 Emergency Reporting Flowchart
 5. S1 Emergency Duty Roster List

3.7.4 Press Release Room (PRR)

Press Release Room (PRR) is located at a room of 1st floor, 30th Year Building. The room is used for information disclosure and issuing public statements to local media or communities in case of emergency.



Figure 8: Photo of Press Release Room (PRR)

3.8 PRESS RELEASE

In the event of an emergency and/or a crisis, a special communication task force is to be set up. The team comprises, at least, a media spokesperson and the Crisis Communications Team (CCT). Their responsibilities include communication with external audiences that are media, authorities, and local communities.

According to PTTEP Delegation of Authority & Signature (DAS), only the President and Chief Executive Officer (CEO) and/or designated representatives of the organization are authorized to disclose information and issue public statements in case of an emergency. The level of spokesperson shall be as the following chart.



In case of an emergency at S1 asset, VP of S1 Production Operations Department (ERTL) or designated representative has the authority as a media spokesperson for disclosure of information and public statement to local media or communities, according to Crisis Communication Guideline (12145-GDL-004-R04) and PTTEP DAS. The information and/or public statement is prepared by S1 CMRT and reviewed & approved by PTTEP Crisis Communication Team (CCT) and EMT Leader prior to the press release. ERTL will provide the press release to local media or communities at Press Release Room (PRR) located at S1 SSHE Induction Room.

Examples of communication tools (as follows) are illustrated in **Appendix E**.

- Key Messages
- Media Release Template
- 1st Telephone Message to Answer Media and Investor Enquiries
- Holding Statement

3.9 DEACTIVATION AND POST EMERGENCY ACTIONS

3.9.1 Deactivation

The EMT Leader, in consultation with S1 ERTL, is the sole authority for deactivating an emergency declaration. Deactivation should only be called when S1 ERTL and EMT Leader agree that the emergency has been contained, and satisfactorily safe in all respects.

The activities and procedures which must be undertaken to recover from an emergency, the EMT Leader shall ensure the conducting of the following activities include, but are not limited to:

- The cleanup, maintenance, and testing of equipment;
- The re-commissioning of facilities, plant, and equipment;
- The replenishment of stocks (such as firefighting foam, spill clean-up materials, replacement parts);
- The accounting for all expenses incurred as a result of the incident;
- The filing of insurance claims; and
- Preparation and dispatch of final reports to relevant Shareholders, Government, and Local Authorities.

3.9.2 Emergency End and Final Actions

Once a decision has been made that no further actions are outstanding and that an emergency is over, many issues need to be considered before standing down. There is a need to consider the following:

- If the severe impact taken place with the production continuity as a result of incident, the S1 Business Continuity Plan (BCP) shall be activated referring to Thai Onshore Asset (PTN) Business Continuity Plan (BCP) (Document Code: 63984.1/2017)
- Ascertain the current position of each team member as regards their role, responsibilities and any ongoing/ outstanding actions;
- Identify and assign any outstanding actions including debriefing of interested external parties, such as authorities, community, etc;
- Put in place an emergency situation review to ensure the completion of outstanding actions;
- Understand any outstanding human resource issues and ensure that the necessary information is provided and the appropriate steps are being taken;
- Ensure that all staff are aware of the emergency close out and update them regarding the short and long-term issues affecting the company (if known);
- Ensure that all information has been captured and recorded;

- Have a team debrief before staff leave or return to normal duties;
- Ensure the plan of a future debrief time when all actions can be analysed. This can usually be within 24 - 48 hours of emergency closeout. Consider including the participation of independent reviewers; and
- This review should also address the sensitivity of the report information and determine the most appropriate means of secure storage.

After the review, a closeout report should be prepared. The report should cover the following:

- Understand and document the cause(s) of the emergency;
- Document all involved parties and details of participating personnel;
- Analyse the response and identify any learning points to be incorporated into the appropriate procedures and/or to be shared with other parts of the Business;
- Incorporate a full picture of the costs incurred as a result of the incident; and
- Review the effectiveness of all actions taken.

3.9.3 Incident Investigation

Incident investigation shall be conducted in accordance with Incident Management Standard (SSHE-106-STD-600) as soon as possible and when safe to do so. It should be conducted right after the emergency situation has been cleared in order to collect all evidence & facts and capture actual causes of the incident for proper analysis to define the effective mitigations and improvements for recurrence prevention and emergency/crisis response strategy.

3.9.4 Post Emergency Review

A post-emergency review is required for conducting to examine the response to the emergency. The EMT Leader and/or S1 ERTL should convene an emergency review meeting. Those attending the review meeting shall include the EMT & ERT members, and all other support team members. Minutes of the review meeting shall be recorded and archived for future analysis. The review meeting shall determine (but not limited to) the following:

- Were employees properly informed of S1 ERP and relevant corporate standards/procedures?
- Did employees respond according to S1 ERP and relevant corporate standards/procedures?
- Were employee's responses timely?
- Were the procedures adequate?
- What were the problems encountered during the response activities?
- What can be improved?

- How can similar events be avoided in the future?

If public emergency services were involved, they shall be invited to participate in the critique.

3.10 TRAINING AND EXERCISE

All concerned personnel who are assigned as the emergency response team shall be trained and have competency for their emergency response roles and responsibilities. Training requirements for personnel involving emergency response are illustrated in S1 SSHE Training and Competency Procedure (13247-PDR-SSHE-305/01) and PTTEP SSHE Training and Competency Standard (SSHE-106-STD-340).

Emergency exercise shall be regularly performed by S1 emergency response team members according to the set plan agreed by S1 management. These emergency exercises and drills are to enhance the knowledge & skills of the members and to test the effectiveness of existing ERP for improvement.

3.11 S1 DUTY ROSTER GUIDELINE

The S1 duty roster is designed to provide effective support around the clock for resolving the emergency situation. The duty persons are appointed by the ERT members in each discipline to act on their behalf when they are not readily available to respond to emergency calls. They shall be trained and competent to respond to emergency in their given discipline's roles.

All duty persons are expected to be contactable at all times during their duty period. All duty persons shall respond to all emergency call and take their given roles to support the emergency. When called in, they shall proceed to their designated emergency station the soonest within 2 hours.

The ERT duty persons shall act in emergency response until released by the ERT member in the given discipline.

The duty roster consists of two groups as follows:

3.11.1 ERT Duty Roster

ERT Essential Duty Group:

The ERT essential duty group is the main group that will always be called in when emergency tier 2 & 3 is initiated. The ERT essential duty group comprises the following persons:

- Domestic Onshore Asset Duty (S1, PTTEP1 and SPH)
- Duty Officer
- Event Logger
- SSHE Officer
- SSHE Duty
- Logistics Duty

- Maintenance Duty
- IT/ Telecom Services
- Security Services
- Medical Team
- Community & Media Response Team (CMRT) Duty
- Relative Response Team (RRT) Duty

For the essential duty group, the duty officer (S1 Production Superintendent) is a key person for coordination with other duty persons including on-call support team on emergency supports.

On-Call Support Team Duty Persons:

The On-Call Support Team Duty Group will be assigned from various disciplines' representatives working within S1 operation premise. The selected persons will be called in when their related discipline has sustained an emergency or ER Team Leader / EMT requires assistance. The On-Call Support Team Duty Group is comprised of (but not limit to) the following groups:

- Drilling Duty – ETN SSHE
- Well Services Duty
- Construction Duty
- Material Yard Duty

In addition to above duty groups, the register of S1 duty roster shall include other support staffs of S1 operation department for fulfilling support on emergency situation as required.

Depending on the different roles and responsibilities of duty staff, mobilization time to LKU office for support emergency are varied as follows:

- Available immediately (restricted to shift staff working on facilities including duty officer, event logger, SSHE officer, security services, medical team, well services duty);
- Within 2 hours (key support staff e.g. SSHE duty, logistic duty, maintenance duty, CMRT duty, RRT duty, drilling duty, construction duty, material yard duty, IT/Telecom).

The example of S1 duty roster for emergency response as per duty group classification and mobilization period is illustrated in **Appendix F**.

Back-up Duty Roster Team:

If an emergency takes long time to last, ER Team Leader and/or Duty Officer shall consider having a relieve team. The Duty Roster Team in a later week will be called for backup.

In the event of two emergencies happen at the same time, the Back-up Team will be called.

3.11.2 Duty Roster Nomination

Staff are nominated by their line managers/supervisors for duty roster for a period 7 consecutive calendar days, starting on Monday at 12:00 hrs. The duty roster will be updated to all duty staff and Corporate SSHE division by S1 SSHE department as per weekly basis. The roster will be distributed every Thursday to the following week's duty holders, and the personnel who will be on duty during the following weeks. This will include key personnel such as Telecom Officer. The assigned Department Focal Points are responsible for providing the Corporate SSHE Division with information regarding the forward planning of the Duty Roster. Changes during a Duty Roster Week are allowed, but it shall be the responsibility of the person scheduled for duty. The change must be amicably agreed by the nominated recipient and shall be communicated, by the person requesting the change, to S1 SSHE Department focal point (Officer, Data Management (SSHE) or assigned person). The requested change shall only be to another qualified duty person in the group.

3.11.3 Communication for Duty Roster Personnel

Staff on Duty Roster will receive an Emergency Duty Book which consists of a log book and contact list. Details of all calls, received and transmitted, should be entered into the log book. The Emergency Duty Book must be handed over to the next person of duty.

1. DUTY ROSTER MOBILE PHONE TEST

The Duty Roster mobile phone will be tested by LKU Telecom Officer every Monday at 13:00 hrs. The message will be;

- "Duty Telephone Test, please confirm it is working ... over".

(ทดสอบการติดต่อโทรศัพท์ ครับ ไม่ทราบชัดเจนหรือไม่ ครับ)

This is to ensure that the mobile phones are workable and also to remind duty persons that they are on duty.

If by 16.00 hrs. the Duty Person has not been phoned, he/ she must ring LKU Telecom Officer and report that they did not receive the test call.

The Operator, Telecom Services will then test that number again.

2. GENERIC DUTY ROSTER RESPONSIBILITIES

- Be available and be within the mobilization time radius of LKU Office at all times;
- Carry the duty mobile phone at all times;
- Ensure that the mobile telephones are always working;
- Be aware of specific responsibilities during an emergency;
- When receiving an emergency call, respond as directed by the call message;
- Immediately report any problems with duty communications equipment to Operator, Telecom Services;

- Inform S1 SSHE Department focal point (Officer, Data Management (SSHE)) of any changes to the published duty roster;
- Must not have a blood alcohol level above the National legal limit;
- Notify S1 SSHE Department focal point (Officer, Data Management (SSHE)) of any changes in mobile telephone numbers.

3. DUTY ROSTER PERSONNEL QUALIFICATION REQUIREMENT

The Duty Roster personnel shall be qualified and be approved by SVP, Thai Onshore Asset (EMT Leader). Each discipline is required to have the following qualifications;

- Duty Roster Team members shall be assigned from experience and competence personnel of each discipline;
- Expertise in their areas of responsibility, including knowledge and experience;
- Understand the PTTEP EMP and S1 Emergency Response Plan and know the response process under his/her responsibilities;
- Bilingual – Fluent in both written & spoken Thai & English;
- Has no record of disabilities that may impair his/her ability to perform the functions assigned to them;

All Duty Roster Personnel shall receive training and participate in the emergency response exercise as indicated **Table 6**.

Table 6: Training Requirement and Exercises of S1 Duty Roster

Training Course	Recommended for	Frequency	Responsible Parties
PTTEP Emergency Management Plan (EMP) Introduction and Incident Command Introduction	All new Duty Roster personnel	Yearly	Corporate Security Section
S1 Emergency Response Plan Introduction	All new Duty Roster personnel	Yearly	S1 SSHE Department
Exercise	Recommended for	Frequency	Responsible Parties
Table Top	Selected from Weekly Duty Roster personnel	As appropriated or at least yearly	S1 SSHE Department
Tier 2	Selected from Weekly Duty Roster Team	Yearly	Corporate Security Section and S1 SSHE Department
Tier 3	Duty Roster Team and Crisis Management Team	Yearly	Corporate Security Section and S1 SSHE Department
Note: For table top exercises, to ensure that all duty persons understand and confidence to deal with the real emergency, the frequency of table top exercises shall be more frequency. The exercises can be both informing in advance and surprising without advance informed.			

APPENDICES

APPENDIX A: EMERGENCY CALL MESSAGE FROM LKU TELECOM OFFICER

The emergency call messages that need to be informed to Emergency Response Team, on-call support team and involved parties by LKU Telecom Officer are as follows:

- Tier 1 Emergency at.....For information and standby.
(ขณะนี้เหตุการณ์ฉุกเฉิน ระดับ 1 ที่.....แจ้งเพื่อทราบ และเตรียมความพร้อม)
- Tier 2 Emergency at.....Go to S1 Emergency Coordination Centre (ECC) immediately.
(ขณะนี้เหตุการณ์ฉุกเฉิน ระดับ 2 ที่..... กรุณามาที่ศูนย์ประสานงานเหตุฉุกเฉินทันที)
- Tier 3 Emergency at.....Go to S1 Emergency Coordination Centre (ECC) immediately.
(ขณะนี้เหตุการณ์ฉุกเฉิน ระดับ 3 ที่..... กรุณามาที่ศูนย์ประสานงานเหตุฉุกเฉินทันที)
- Emergency is over. (ขณะนี้เหตุการณ์เข้าสู่ภาวะปกติ)

APPENDIX B: INITIAL EMERGENCY REPORT FORM

This form will be completed by LKU Telecom. Operator on receiving notification of an emergency.

แบบฟอร์มการแจ้งเหตุการฉุกเฉินเบื้องต้น				
รายละเอียดผู้แจ้งเหตุฉุกเฉิน				
ชื่อผู้แจ้งเหตุ:		เบอร์โทรศัพท์ผู้แจ้งเหตุ:		
วันและเวลาที่แจ้งเหตุ:				
รายละเอียดเหตุฉุกเฉิน				
วันและเวลาที่เกิดเหตุ:				
สถานที่เกิดเหตุ:				
ประเภทของเหตุฉุกเฉิน	<input type="checkbox"/> ไฟไหม้ <input type="checkbox"/> ระเบิด <input type="checkbox"/> ก๊าซรั่วไหล <input type="checkbox"/> สารเคมี/น้ำมันรั่วไหล <input type="checkbox"/> อุบัติเหตุทางถนน <input type="checkbox"/> การก่อการร้าย <input type="checkbox"/> อื่นๆ โปรดระบุ			
รายละเอียดของเหตุฉุกเฉิน:				
ผู้แจ้งเหตุต้องการความช่วยเหลือหรือไม่	<input type="checkbox"/> ใช่ <input type="checkbox"/> ไม่ใช่			
ความช่วยเหลือที่ต้องการ	<input type="checkbox"/> การช่วยทางการแพทย์ <input type="checkbox"/> การค้นหาผู้สูญหาย/การช่วยชีวิต <input type="checkbox"/> การตอบสนองต่อการรั่วไหล <input type="checkbox"/> การช่วยเหลือด้านเทคนิค <input type="checkbox"/> อื่นๆ โปรดระบุ			
รายละเอียดด้านบุคคล				
รายละเอียด	พนักงาน ปตท.สม.	ผู้รับเหมา	บุคคลที่สาม	ไม่ทราบ/ไม่สามารถระบุได้
จำนวนผู้เสียชีวิต				
จำนวนผู้บาดเจ็บ				
จำนวนผู้สูญหาย				
รายละเอียดด้านสิ่งแวดล้อม				
ระบุชื่อวัสดุที่รั่วไหล				
ปริมาณการรั่วไหล (ถ้ามี)				
รายละเอียด ณ จุดเกิดเหตุ				
มีตัวแทนของบริษัทฯ อยู่ ณ จุดเกิดเหตุหรือไม่	<input type="checkbox"/> มี <input type="checkbox"/> ไม่มี ถ้ามี โปรดระบุ ชื่อ เบอร์ติดต่อกลับ			
การดำเนินการ ณ จุดเกิดเหตุ				
ชื่อผู้บันทึกเหตุ	วันและเวลาที่บันทึกเหตุ:			



APPENDIX C: EMERGENCY LOG SHEET




See next page.



รายละเอียดเหตุการณ์			ชื่อผู้บันทึก: ตำแหน่งผู้บันทึก: วันที่:	
เวลา	ข้อความ		รายละเอียดของเหตุการณ์	หมายเหตุ
	จาก	ถึง		




APPENDIX D: LOCATION OF PREDETERMINED MUSTER POINTS




The locations of predetermined muster points, positions of Muster Checker and Muster logger of each S1 operating location are shown in below table.


Table 1: The muster points, positions of Muster Checker and Muster logger of each S1 operating location

No.	S1 Operating Location	Location of Muster Point	Mustered Person	Position of Muster Checker	Position of Muster Logger	Photo of Muster Point
1	LKU Flow Station, accommodation, maintenance workshop, officer	Behind Fire Station Building	Emergency Response Team, personnel working in LKU Flow Station, personnel working in the office area, maintenance workshop, visitors	Well Site Supervisor #2	S1 SSHE Officer (Shift)	
		In front of CCR	Emergency Response Team within LKU Flow Station	LKU Plant Foreman	S1 SSHE Officer (Shift)	
		In front of Piyachat Nithat (PNEC) Building	Persons working at PNEC building and their visitors Persons working at OJT center building and their visitors	Public Affair Staff	S1 SSHE Officer (Shift)	

No.	S1 Operating Location	Location of Muster Point	Mustered Person	Position of Muster Checker	Position of Muster Logger	Photo of Muster Point
2	NTM-A	By the security guardhouse at the main gate.	Persons working at NTM-A, contractors, visitors	NTM-A Security Guard	NTM-A Production Lead Operator	
		In front of NTM-A control room	Site Operation Team/ Emergency Response Team	NTM-A Production Operator	NTM-A Production Lead Operator	-
3	STN-A	Beside security guardhouse by the main gate.	Persons working in STN-A, contractors, visitors	STN-A Security Guard	STN-A Production Operator	
		In front of STN-A control room	Site Operation Team/ Emergency Response Team	STN-A Production Operator	STN-A Production Operator	-

No.	S1 Operating Location	Location of Muster Point	Mustered Person	Position of Muster Checker	Position of Muster Logger	Photo of Muster Point
4	Well Sites	Outside by the main gate	Persons working within well sites, contractors, visitors	Security Guard	Area Operator	
5	BPR Depot	In front of T-904 (Road tanker area)	Emergency Response Team, persons working at road tanker area within BPR Depot, visitors	Security Guard (Road tanker area)	BPR Depot Operator	
		In front of the security guardhouse (Rail tanker area)	Emergency Response Team, persons working at rail side area within BPR Depot, visitors	Security Guard (Rail tanker area)	BPR Depot Operator	

No.	S1 Operating Location	Location of Muster Point	Mustered Person	Position of Muster Checker	Position of Muster Logger	Photo of Muster Point
6	Well Service Workshop	In front of the main gate	Persons working within well service workshop, visitors	Senior Technician (workshop)	Well Service Supervisor	
7	Material Yard	In front of the main gate	Persons working within the material yard, visitors	Senior Store Keeper	Team Leader, Warehouse and Material Yard	
8	PHS Housing Compounds	Car park area	Persons living in PHS housing compounds, persons working (gardeners, housekeepers), visitors	Security Guard	Security Guard	

No.	S1 Operating Location	Location of Muster Point	Mustered Person	Position of Muster Checker	Position of Muster Logger	Photo of Muster Point
9	CNS Rail Tanker Maintenance Workshop	In front of the security guardhouse	Persons working CNS rail tanker maintenance workshop, visitors	CNS Contractor (JS TECH) SSHE Officer	CNS Contractor (JS TECH) Site Manager	

APPENDIX E: EXAMPLES OF COMMUNICATION TOOLS

1. Key Messages

These key messages should be conveyed in all communications to all stakeholders of PTTEP.

- In conducting exploration and production of petroleum and other activities in accordance with its mission, PTTEP, strives at all times to achieve a manner ensures that incidents affecting the health and safety of its employees, contractors and member of the public, the environment and the integrity of its assets shall not occur.
- PTTEP's primary concern in all incidents of this nature is for the people involved. PTTEP staff have been trained to strictly follow the emergency plan to ensure maximum safety for themselves, partners and rescue workers.
- The nature of PTTEP's business demands the most stringent Safety, Security, Health, and Environmental standards and the company remains committed to maintaining the highest possible standards in this vital area in all its activities.


ข้อความการสื่อสารหลัก

ข้อความการสื่อสารหลักสำหรับผู้มีส่วนได้ส่วนเสียของ ปตท.สผ. กลุ่มต่างๆ

- ในการดำเนินการสำรวจและผลิตปิโตรเลียมรวมทั้งกิจกรรมอื่นๆ ปตท.สผ. มีแนวทางปฏิบัติเพื่อป้องกันมิให้เกิดเหตุการณ์ที่จะส่งผลกระทบต่อสุขภาพและความปลอดภัยของพนักงานบริษัทฯ ผู้รับเหมาและบุคคลทั่วไป รวมทั้งสภาพแวดล้อมและทรัพย์สินของบริษัทฯ
- ในสถานการณ์ดังกล่าว ปตท.สผ. ห่วงใยในสวัสดิภาพของพนักงานที่เกี่ยวข้อง อย่างไรก็ตาม พนักงานของ ปตท.สผ. ทุกคนได้ผ่านการฝึกฝนให้ปฏิบัติตามแผนการในภาวะฉุกเฉินโดยเคร่งครัด เพื่อให้เกิดความมั่นใจ
- ในความปลอดภัยสูงสุดของพนักงาน พันธมิตรธุรกิจ และเจ้าหน้าที่กู้ภัย ด้วยลักษณะของธุรกิจของ ปตท.สผ. บริษัทฯ ยึดถือหลักเกณฑ์และมาตรฐานที่เข้มงวดที่สุดด้านสุขภาพ ความปลอดภัย และสิ่งแวดล้อม บริษัทฯ มุ่งมั่นปฏิบัติตามหลักการดังกล่าวมาโดยตลอด เพื่อรักษามาตรฐาน สูงสุดในการปฏิบัติงานด้านดังกล่าว

2. Media Release Template

The Media Release Template gives an overview of the structure and content of a press release or a statement, in line with the common way press releases are written. Using this template helps the Writer develop a press release or a statement quickly and in a consistent way. The Writer and Media Relations Team work closely together to ensure they receive all information as per the template.



News Release

ข่าวประชาสัมพันธ์

Date : _____
Time : _____

Headline (subject matter)


What happened : _____
Where it happened : _____
When did it happen (date, time) : _____
Services involved : _____
Current situation as verified by facts : _____
Effect on stakeholders (JVs, partners, government, suppliers, public) : _____
Status of investigation/recovery : _____
Which government agencies are involved : _____
Any additional information : _____

For further information, please contact : _____
Contact details
Name and designation _____
Tel : _____
Fax : _____
Email : _____

Disclaimer
The information, statements, forecasts and projections contained herein reflect the Company's current views with respect to future events and financial performance. These views are based on assumptions subject to various risks. No assurance is given that these future events will occur, or that the Company's future assumption are correct. Actual results may differ materially from those projected.

บริษัท ปตท.สำรวจและผลิตปิโตรเลียม จำกัด (มหาชน)
PTT Exploration and Production Public Company Limited

www.pttep.com



ปตท.สำรวจและผลิตปิโตรเลียม จำกัด (มหาชน) | Passion to Explore for a Sustainable Future

3. 1st Telephone Message to Answer Media and Investor Enquiries

Based on the latest report on _____(date) at _____(time 24 hours) we obtained, there was a/an _____ at _____. The cause of the incident is still unclear. However, the company is doing its best (to evacuate all staff) (and extinguish then fire/control the spill). Please tell me your name, the publication you represent, the telephone number and email address. For any further update on this situation, please visit www.pttep.com. Thank you.

ข้อความแรกในการตอบโทรศัพท์สื่อมวลชน

จากรายงานที่บริษัท ปตท.สำรวจและผลิตปิโตรเลียม จำกัด (มหาชน) ได้รับเมื่อเวลา_____วันที่_____ได้เกิดเหตุ _____ ขึ้นที่ _____ สาเหตุของอุบัติเหตุยังไม่ทราบแน่ชัด อย่างไรก็ตาม บริษัทฯ กำลังดำเนินการอย่างเต็มที่เพื่อ _____ (อพยพพนักงาน และดับเพลิง หรือกำจัดคราบน้ำมัน) ขอทราบชื่อของคุณ ชื่อสื่อที่สังกัด หมายเลขโทรศัพท์ และ e-mail ทั้งนี้ คุณสามารถติดตามรายละเอียดความคืบหน้าของเหตุการณ์ได้ที่เว็บไซต์ www.pttep.comค่ะ/ครับ

4. Holding Statement

Tips on Writing a Holding Statement

- Three paragraphs
 - Keeps to facts
 - What is being done
 - Some context about the company
- Keep it short and factually accurate
- Avoid emotive language
- Don't prompt further questions
- Avoid digging holes which you can fall into later
- Don't commit to anything - unless it is your intention to do so
- State date (time) and contact details

Note:

Never make statements like "There was no loss of life or injury to staff members resulting from the incident." unless this is confirmed.

Such statements made prematurely will reflect badly on the company if ultimately deaths and/or injuries have occurred.

If not yet confirmed, say something like: "Up till now, we have not received reports of any loss of life or injuries." Then you may add: "Information is still coming in and we will update you as and when we get it."

หมายเหตุ:

ไม่ควรระบุว่า "ไม่มีการบาดเจ็บหรือเสียชีวิตจากเหตุการณ์ที่เกิดขึ้น" จนกว่าจะมีการยืนยันแน่นอน มิฉะนั้นจะส่งผลเสียอย่างมากต่อบริษัท หากยังไม่ได้รับการยืนยันที่แน่นอนว่า มีผู้เสียชีวิต และ/หรือ ผู้บาดเจ็บจริง ควรชี้แจงว่า "จนถึงขณะนี้ เรายังไม่ได้รับรายงานเกี่ยวกับผู้เสียชีวิตหรือผู้บาดเจ็บ" และเสริมว่า "ข้อมูลเพิ่มเติมจะมาถึงในเร็วๆ นี้" และบริษัทฯ จะแจ้งความคืบหน้าให้ท่านทราบทันทีที่ได้รับข้อมูล"

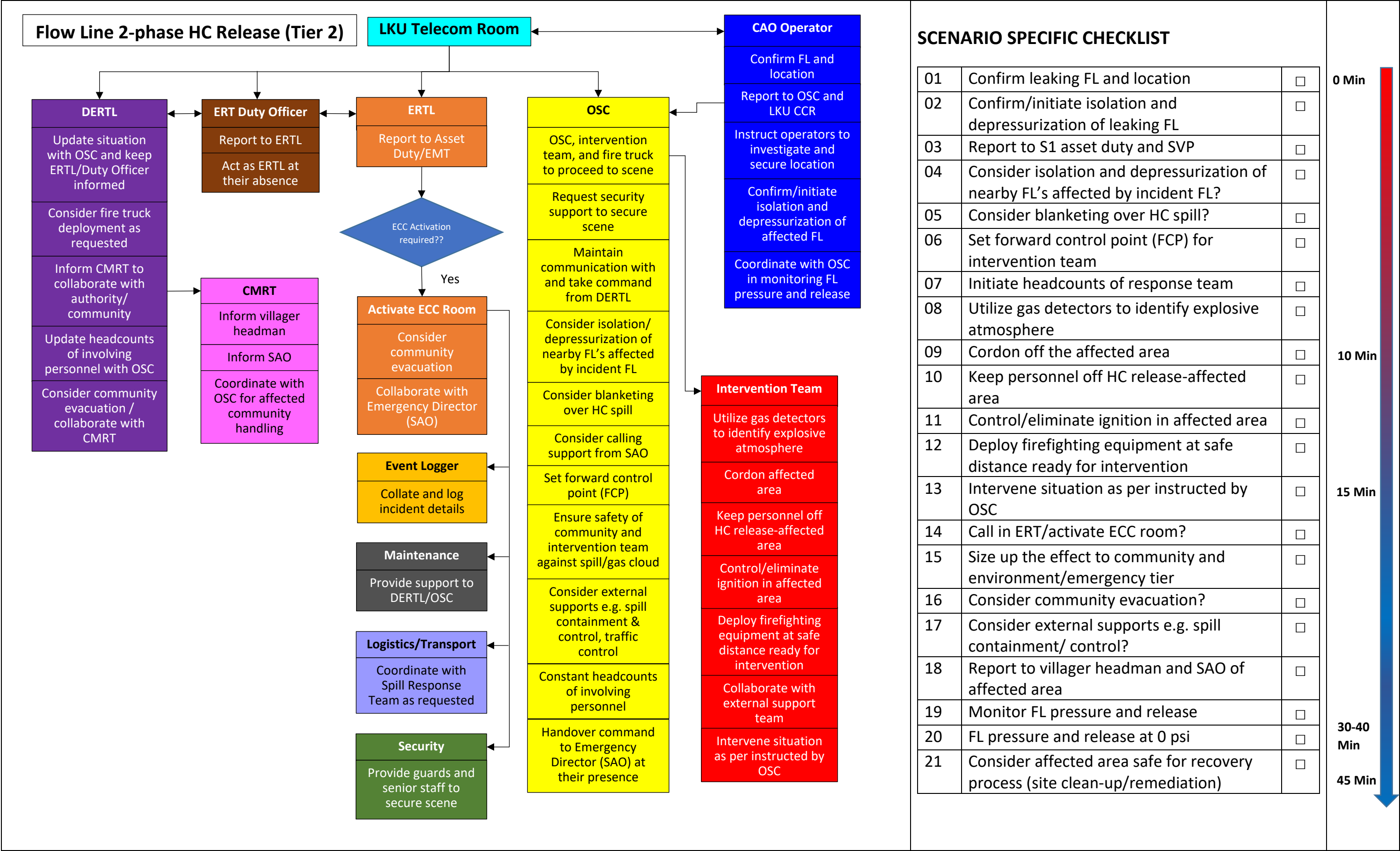
APPENDIX F: EXAMPLE OF S1 DUTY ROSTER

S1 Duty Roster for Emergency Response					
	24-Jun-2019		To	01-Jul-2019	
Operator, Telecom. Services (LKU)					
First point of call	LKU Office			055-731150, 055-718-999, 02-537-6099 Internal line 33 or 810-6099	
ERT Main Duty Group					
Pool Field (Available immediately in the Field)					
Role	From	To	Name	Office	Mobile
Duty Officer	24/06/19	1/7/2019	Nakrop P.	810-6238	081-7855476
Event Logger	24/06/19	1/7/2019	Tattanan P.	810-6187	-
SSHE Officer	24/06/19	1/7/2019	Charun C.	810-6100, 810-6163	084-387-9416
Security Services	-	-	-	810-6045, 810-6069	-
Medical Team (LKU Nurse/Ambulance)	-	-	-	810-6038	081-2817664
Contactable 24 hours, Mobilize in 2 hours					
Role	From	To	Name	Office	Mobile
Domestic Onshore Asset Duty	24/06/19	1/7/2019	Noppadol B.	800-4616	097-4964975
SSHE Duty	24/06/19	1/7/2019	Ronachai F.	810-6298	089-7711212
Logistics Duty	24/06/19	1/7/2019	Vuthichai K.	810-6190	081-9949340
Maintenance Duty	24/06/19	1/7/2019	-	810-6150 (Officer hour)	098-2710948 (After office hour)
IT/Telecom Services	24/06/19	1/7/2019	Jirasak T.	6304	081-7855485
Community & Media Response Team (CMRT) Duty	24/06/19	1/7/2019	Panlop L.	810-4507	089-9681219
Relative Response Team (RRT) Duty	24/06/19	1/7/2019	Jantana N.	810-6292	XXXXXXX
On-Call Support Team Duty Persons					
Pool Field (Available immediately in the Field)					
Role	From	To	Name	Office	Mobile
Well Services (Superintendent)	24/06/19	1/7/2019	Chalit D.	810-6082, 810-6006	081-7855487
ETN SSHE Duty	24/06/19	1/7/2019	Saralrasm T.	810-6118	098-8297650
Contactable 24 hours, Mobilize in 2 hours					
Construction Duty	24/06/19	1/7/2019	Teerayut I.	810-6168	089-9618611
Material Yard Duty	24/06/19	1/7/2019	-	810-6064	081-7519345



APPENDIX G: INCIDENT GUIDELINE FOR EMERGENCY SITUATIONS

<< File embedded in PDF >>



ROLES AND RESPONSIBILITIES

Roles	Responsibilities
Document Owner	<p>The owner of the S1 Emergency Response Plan is VP, S1 Production Operations Department, with responsibilities for:-</p> <ul style="list-style-type: none"> ■ Issuing the S1 Emergency Response Plan and its revisions; ■ Issuing the S1 Emergency Response Plan and its revisions; and ■ Ensuring effective implementation of the plan.
Document Custodian	<p>The custodian of the S1 Emergency Response Plan is Superintendent, SSHE, with responsibilities for:-</p> <ul style="list-style-type: none"> ■ Identify deficiencies or potential improvements; ■ Initiating periodic revision; and ■ Maintaining revision history and document status register.

DEFINITION AND ACRONYMS

Set out below are common specific terms presented in alphabetical order:

Term	Definition
Asset	Refers to an operating Asset, site, or location within a respective Function Group.
Corporate	Refers to the PTTEP business groups hierarchically above Asset level, and located in the PTTEP headquarters, Bangkok.
Division	A business group may have one or more distinct groups within its hierarchy. These are referred to as Divisions.
Department	A subgroup within a Function Group, Division or Asset.
Function Group	Refers to a corporate level business group. These may have associated Divisions, Departments, or operational Assets within their hierarchy.
Crisis	<p>is a major or catastrophic event (out of control emergency). A crisis could result in sustained national impacts over a prolonged period of time; almost immediately exceeds resources normally available to the company, local authorities, and country in the impacted area; and significantly interrupts governmental operations and emergency services to such an extent that national security could be threatened. The crisis may challenge the ability and capacity of the company, community, and country to achieve a timely recovery.</p> <p>Crisis situations include terrorism that results in extraordinary levels of mass casualties, damage, or disruption severely affecting the population, infrastructure, environment, economy, company reputation, national morale, and/ or government functions. In PTTEP, a crisis situation is treated by a tier 3 response level.</p>
Crisis Management Team (CMT) Leader	The Chief Executive Officer (CEO) of the company who has the top authority to the overall management of a group/ company impact related to any crisis situations. He has the authority to activate the Corporate Crisis Management Team and work closely with the Asset Emergency Management Team Leader.
Emergency	is an occurrence or event, natural or human-caused, that requires an emergency response under the determination of affected asset leader or acting person, to protect life, environment, property, and reputation or to lessen or avert the threat of a major or catastrophe in any part of the company premises. The external assistance may or may not be needed to supplement the company's efforts and

Term	Definition
	<p>capabilities to save lives, environmental, protect property, public health and safety.</p> <p>Emergency situations can, for example, include major disasters, emergencies, terrorist attacks, terrorist threats, fires, floods, oil, and hazardous material spills, marine vessels and aircraft accidents, earthquakes, tropical storms, typhoon, war-related disasters, an outbreak of diseases and medical emergencies, and etc.</p> <p>In PTTEP emergency situations can be evaluated and treated by using a tier 1 – 2 response level.</p>
S1 Emergency Management Team Leader (EMT Leader)	<p>S1 asset's SVP or the acting person who has overall authority and responsibility for supporting and providing tactical advice, activities, and action plans to the S1 ERT or On-Scene Commander (OSC), including the development of strategic objectives. EMT leader also sets priorities and defines the organization of the EMT and the overall action plans for a particular response. He/she has to work closely with asset EMT.</p>
S1 Emergency Response Team Leader (ERT Leader)	<p>S1 VP with responsibility for all onsite responses, especially providing directions and onsite tactical operations and always retaining the authority to determine the appropriate course of response actions. S1 ERT leader has the authority to activate the S1 ERT.</p>

Acronyms	Description
DERTL	S1 Deputy Emergency Response Team Leader
ECC	Emergency Coordination Centre
ERP	S1 Emergency Response Plan
ERT	S1 Emergency Response Team
ERTL	S1 Emergency Response Team Leader
CMRT	S1 Community & Media Response Team
OSC	S1 On-Scene Commander
RRT	S1 Relative Response Team
EMT	S1 Asset Emergency Management Team
CMT	PTTEP Crisis Management Team
SAO	Sub-district Administrative Office
OSRL	Oil Spill Response Limited Company
EARL	East Asia Response Limited Company
IESG	Oil Industry Environment Safety Group Association of Thailand
LKU	Area of Lan Krabue District, Kampanget Province
ITL	Intervention Team Leader
NTM	Nong Tum Sub-district, Kong Krai Lad District, Sukhothai Province
PHS	Phitsanulok Province
CNS	Chong Nonsi, Bangkok
CCT	PTTEP Crisis Communication Team
CMRR	Communication and Media Response Room
VP.	Vice President

Acronyms	Description
SVP.	Senior Vice President
CSR	Company Site Representative

REFERENCES

Document Code	Document Title
PTTEP SSHE Controlling Documents	
11038-STD-SSHE-000	PTTEP SSHE Management System
11038-STD-SSHE-401	PTTEP SSHE Risk Management Standard
SSHE-106-STD-500	PTTEP Emergency and Crisis Management Standard
12148-PDR-SSHE-501	PTTEP Crisis Management Plan
SSHE-106-PDR-502	PTTEP Emergency Management Plan
SSHE-106-STD-340	PTTEP SSHE Training and Competency Standard
11003-GDL-SSHE-501-003	PTTEP Medical Emergency Management Guideline
12145-GDL-004-R04	PTTEP Crisis Communications Guideline
13247-PDR-SSHE-305/01	S1 SSHE Training and Competency Procedure
63984.1/2017	Thai Onshore Asset (PTN) Business Continuity Plan (BCP)
Other Reference Documents	
-	Disaster Prevention and Mitigation Act B.E.2550 พรบ.ป้องกันและบรรเทาสาธารณภัย พ.ศ. 2550

REVISION HISTORY

Rev.	Description of Revision
0	<p>Authorized by: -, Date: -</p> <p>New issue.</p>
1	<p>Authorized by: DSA, Date: August 2010</p> <p>Key changes from the previous version are as follows:-</p> <ul style="list-style-type: none"> ■ Re-formatted from SSHE-ER-01, S1 Emergency and Crisis Response Plan; ■ Aligned with new PTTEP SSHE MS, ISO14001:2004 and OHSAS18001:2007 requirements; ■ Current ERC (PS1/P) is changed to OSC (On-Scene-Commander) as per corporate guideline; ■ Current OSC is changed to Intervention Team Leader(s); ■ Added emergency plan for Protesting/Demonstration & Terrorist; and ■ Updated Organizational Indicators.
2	<p>Authorized by: DSA, Date: November 2013</p> <p>Key changes from the previous version are as follows:-</p> <ul style="list-style-type: none"> ■ Assigned new document code; ■ Aligned with Corporate Emergency and Crisis Management Standard and Plan; ■ Changed back OSC to be at the incident scene; ■ S1 IC is to be at ECC; ■ Revised role & responsibilities; and ■ Updated emergency contact numbers.
3	<p>Authorized by: PS1, Date: November 2019</p> <p>Major amendment of the whole procedure. Key changes from the previous version are as follows:-</p> <ul style="list-style-type: none"> ■ Aligned with the Corporate Emergency Management Plan and Crisis Management Plan; ■ Revised S1 Emergency Response Team Organization with their roles and responsibilities; ■ Revised emergency response action; and ■ Included sections of S1 duty roster guideline, must points and press release.



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รายงานผลการปฏิบัติตามมาตรการป้องกันและแก้ไขผลกระทบสิ่งแวดล้อม และมาตรการติดตามตรวจสอบผลกระทบสิ่งแวดล้อม
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ฉบับเดือนมกราคม – ธันวาคม พ.ศ.2565

ภาคผนวกที่ 16
Blowout Contingency Plan



PTT Exploration and Production Public Company Limited

**Blow Out Contingency Plan
Manual**

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Table of Contents

1.0	Purpose	5
2.0	Scope	5
2.1	Language	5
3.0	References	6
3.1	PTTEP Internal References	6
3.2	International References	6
3.3	Regional References	6
4.0	Definitions	7
4.1	Well Barrier Definitions	7
4.2	General Definitions	8
4.3	Organisation and Departments	9
4.4	LANGUAGE	9
4.5	Common Acronyms	10
5.0	Responsibilities	13
5.1	Document Owner	13
5.2	Document Custodian	13
6.0	Introduction	14
6.1	Objective of the Plan	14
6.2	Scope of the Plan	14
6.3	BCP Plan Summary	14
6.4	Control of a Drilling Emergency	15
6.5	Multiple Emergency Potential	15
6.6	Coordination of Efforts	16
6.7	Notification	16
6.8	ICS Principal	16
7.0	Notifications and Incident Levels	24
7.1	Incident Response Levels	25
7.2	Emergency Response Team (ERT)	26
7.3	Notification, Activation and Assembly	26
8.0	Initial Field Response Action	28
8.1	On Scene Incident Commander and Person in Charge	28
8.2	Personnel Responsibilities and Description	29
8.3	Guidelines for Initial Response	32
8.4	On-Scene Incident Commander & Person in Charge Task Lists	36
8.5	Hot Zone Identification	37
8.6	Hot Zone Access & Egress	41
8.7	Firefighting and Asset Protection	43
8.8	Voluntary Ignition Procedure	45
8.9	Personnel Safety & Victim Management Check List	49
9.0	Blow Out Response Plan Introduction	52
9.1	Emergency Response Team -ERT	52
9.2	Blowout Control Task Force- BCTF	55

9.3	<i>BCTF Members Job Description</i>	56
9.4	<i>Blow Out Response Plan in 1st 24 hours.....</i>	64
9.5	<i>Blow Out Response Plan in Cycle 2-5 days.....</i>	67
9.6	<i>Routine Operations.....</i>	68
9.7	<i>Geological Assistance</i>	69
9.8	<i>Safety Measurements and Assistance</i>	69
10.0	Appendices	70
10.1	<i>Logistical Considerations for Offshore and Major Response</i>	70
10.2	<i>Logistical Considerations for Onshore and Major Response - Important.....</i>	82
10.3	<i>Blowout Scenarios and Commentary</i>	96
10.4	<i>Capping Strategy.....</i>	101
10.5	<i>Surface Intervention, Firefighting & Capping Strategy</i>	101
10.6	<i>Capping Operations.....</i>	109
10.7	<i>Relief Well Interventions.....</i>	129
10.8	<i>Relief Well Planning.....</i>	138
10.9	<i>Relief Well Strategy</i>	159
10.10	<i>Surface Control Special Services</i>	180
10.11	<i>Emergency Contact Lists.....</i>	184

1.0 PURPOSE

This PTTEP document has been written to detail the minimum requirements of projects and assets to comply with the PTTEP Corporate Policy on Blow Out Contingency Planning within the Well Engineering discipline.

This corporate level document provides the framework for the management and assurance of Well Engineering within all PTTEP assets and has the following objectives:

- To specify a mechanism to ensure that PTTEP assets remain fit for service and deliver the required safety, environmental and commercial performance throughout the asset life cycle.
- To provide a basis for the management of equipment reliability and integrity through the assets, business processes and organization.
- To ensure that effort is focused on the equipment most critical to safety, environmental and business performance.
- To ensure that the risk of Major Accident Events (MAE's) are reduced to 'As Low As Reasonably Practicable' (ALARP).
- To be flexible to and reflect operational experience and accommodate change.

PTTEP Assets shall adhere to this document and take account of other guidelines and procedures which shall be applied throughout the well/asset life cycle.

2.0 SCOPE

This document applies to the following project life cycle phases:				
Identify / Assess	Select	Define	Execute	Operate
X	X	X	X	X

This document defines the processes that shall be implemented by all PTTEP onshore & offshore oil and gas production and related assets. The processes shall be applied at project development phase through to abandonment.

Where National Regulatory requirements are more stringent, they shall take precedence over this document. In such cases, the document owner shall be notified to determine whether document revision is required.

2.1 LANGUAGE

In this document, the words may, should, and shall have the following meanings:

May	Indicates a possible course of action
Should	Indicates a preferred course of action
Shall	Indicates a course of action with a mandatory status

3.0 REFERENCES

3.1 PTTEP INTERNAL REFERENCES

Internal documents applicable to this document are indicated in the table below.

Document Number	Document Title
Various	WMS Controlling Documents
Various	SSHE Controlling Documents
Various	CMS Controlling Documents

3.2 INTERNATIONAL REFERENCES

International Standards applicable to this document are indicated in the table below.

Document Number	Document Title
Various	API/ISO Controlling Documents
Various	Norsok Controlling Documents

3.3 REGIONAL REFERENCES

Regional Standards applicable to this document are indicated in the table below.

Document Number	Document Title

4.0 DEFINITIONS

4.1 WELL BARRIER DEFINITIONS

Terminology	Description
Well Barriers	Well barriers are envelopes of one or several dependent Well Barrier elements located on a potential leak path able to stop any fluid flow. Each barrier element shall be designed with regard to fluid characteristics and maximum pressure constraints expected at the considered barrier depth.
Well Integrity Envelope	A well integrity envelope is that which can be a combination of barriers and shall be designed to meet all potential load and environment conditions for the required design life of the well. It is also a means to prevent fluid flow and pressure transmission from one zone to another or to the surface and allow safe well killing operations.
Well Barrier Schematic	Is the drawing that will show the well barrier elements, the envelopes at each stage of the wells lifecycle, from “cradle to grave”.
Primary Barrier	A system which provides first line fluid containment.
Secondary Barrier	A system which provides backup to the primary system.
Tertiary Well Barrier	Third (and generally optional) well barrier that prevents flow from a source and can act as backup to Secondary or Primary Well Barriers.
Independent Barrier	A barrier system which does not rely on another barrier to ensure pressure integrity, e.g. two similar plugs, can be considered as independent, providing that each plug can be regarded as reliable in its own right.
Verified Well Barrier	Whereby appropriate measures have been taken to confirm the Well Barrier will provide the required isolations. In this document, the term “Well Barrier” means a verified Well Barrier.
A barrier is also defined as either permanent or temporary as follows:	
Temporary Barrier	Non-permanent on or in the well; i.e. BOPs, retrievable plugs. Under specific circumstances the drilling fluid or wellbore fluid, or reservoir fluid may be considered a temporary barrier.
Permanent	Those barriers remaining on or in the well to provide permanent isolation.
Well Classification for Barriers:	
Non-Flowing	A well shall be considered as non-flowing if once the injection / activation system is de-activated, once the injecting/producing bore had been bled-off to atmospheric pressure and once well mean temperature is stabilized, no sustained flow can be observed at surface. This test shall be repeated at least once a year or more often if reservoir conditions can vary.
Eruptive	Any well, which does not fulfil the “non-flowing” well criteria, is named Eruptive.

4.2 GENERAL DEFINITIONS

Terminology	Description
Asset	Any physical facilities onshore or offshore used in the exploration, production, processing or transportation of oil and gas, and any supporting facilities or equipment.
Asset Integrity (AI)	Asset integrity is related to the prevention of major accidents. It is the outcome of good design, construction and operating practices. It is achieved when facilities are structurally and mechanically sound and perform the processes and produce the products for which they were designed
Audit	A structured independent assessment of the efficiency, effectiveness and reliability of the process or system.
As Low As Reasonably Practical (ALARP)	A term used to define tolerable risk acceptance only where risk reduction is impractical or cost benefit analysis is carried out and a judgment is made that the cost of further risk reduction is grossly disproportionate when compared to the actual risk reduction that would be achieved.
Hazard	A hazard is an intrinsic property of anything with the potential to cause harm. Harm includes ill-health, and injury, damage to property, plant, products or the environment, production losses, or increased liabilities.
Hazardous activity	Activity or task that exposes the person(s) carrying out the task to a hazard (e.g. welding, falls, etc.).
Hazard Register	The Hazard Register is an assessment record and communication document that demonstrates that all hazards associated with the Facility or Activity have been identified, and their associated risks assessed, such that appropriate risk controls can be implemented.
Major Accident Event (MAE)	Any incident that results in multiple fatalities or equivalent damage, production loss, environmental impact as per the risk matrix.
Mitigation	Limitation of the undesirable effects of a particular event.
Management Review	A systematic and timely study of a facility's equipment and management systems to help ensure safe operation.
Management System	A structured set of interdependent doctrines, processes, documents and principles that are intended to ensure that the activities of an organization are directed, planned, conducted and controlled in such a way to provide reasonable assurance that the objectives of the organization are met.
Quantitative Risk Assessment (QRA)	QRA is the evaluation of the extent of risk arising, with incorporation of Calculations based upon the frequency and magnitude of hazardous events.
Risk	Risk is a combination of the probability of occurrence of a consequence and the severity of that consequence.
Risk Assessment	An overall process of risk analysis and risk evaluation.
Safety Case	A formal demonstration that Health safety and environmental risks associated with the facility have been assessed and are being effectively managed.
Technical Authority (TA)	PTTEP personnel responsible for technical standards, and for providing advice on issues relating to their discipline, including advice on whether proposals to change or to deviate from a standard or from the reliability and integrity envelope should be approved.

4.3 ORGANISATION AND DEPARTMENTS

In this document, the terms Corporate, Division and Asset have the following meanings:

Corporate	Refers to the PTTEP Business Groups hierarchically above Asset level, and located in the PTTEP headquarters, Bangkok.
Group	Refers to a corporate level Business Group. These may have associated Divisions, Departments, or operational Assets within their hierarchy.
Division	A Business Group may have one or more distinct groups within its hierarchy.
Asset	Refers to an operational Asset, site, or location within a respective Business Group.
Department	A subgroup within a Business Group, Division or Asset.
Subsidiaries	Juristic persons which PTTEP is a shareholder of more than 50%.

4.4 LANGUAGE

In this document, the words may, should, and shall have the following meanings:

May	Indicates a possible course of action
Should	Indicates a preferred course of action
Shall	Indicates a course of action with a mandatory status

4.5 COMMON ACRONYMS

/E	Engineering
/O	Operations
ACV	All-Purpose Capping Vehicle
ALARP	As Low As Reasonably Practicable
AMSL	Average Mean Sea Level
API	American Petroleum Institute
B&C/IWC	Boots & Coots IWC
BCP	The Blowout Contingency Plan
BCTF	Blowout Contingency Task Force
BHA	Bottom Hole Assembly
BOP	Blow Out Preventer
BOPE	Blow Out Prevention Equipment
BOPs	Blow Out Preventers
BPV	Back Pressure Valve
CMP	Crisis Management Plan
CMS	CMS Controlling Documents
CMT	Crisis Management Team
CO ₂	Carbon Dioxide
CP	Command Post
CSE	Safety, Security, Health and Environment Division
CWCI	Cudd Well Control
DC	Drill Collars
DMF	Department of Mineral Fuels
DP	Drill Pipe
DSV	Drill Supervisor
E.C.R.	Emergency Control Room
E.V.P / EVP	Executive Vice President
EMP	Emergency Management Plan
EMS	Electro Magnetic Survey
EMT	Emergency Management Team
EPA	Environmental Protection Agency
EPC	Procurement
EPS	EVP, Eng., Operations & SC
ERP	Emergency Response Plan
ERT	Emergency Response Team
ESD	Emergency Shut Down
ETA	Estimated Time of Arrival
EU	European Union
EZ	Exclusion Zone
FAC	Accounting Division
FNA	Finance & Accounting Group
GSX	Geoscience & Exploration Group

H ₂ S	Hydrogen Sulfide
HDY	Hat Yai Airport designation - IATA
HHP	Hydraulic Horse Power
HHR	Personnel Administration
HIT	Information Technology & Information Management Dept.
HRS	Human Recourses & Business Services Group
HSE	Health, Safety, and the Environment
HTHP	High Temperature High Pressure
IATA	International Air Transit Association
ICAO	International Civil Aviation Organization
ICS	Incident Command Structure
IESG	Oil industry Environment Safety Group Association of Thailand
ISO	International Organization for Standardization
KOP	Kick Off Point
LEL	Lower Explosive Limit
MAE	Major Accident Event
MASP	Maximum Anticipated Surface Pressure
MNL	Manual
MODU	Mobile Offshore Drilling Units
MSV	Primary Support Vessel
MWD	Measurement While Drilling
N ₂	Nitrogen
OIC	On-Scene Incident Commander
OIM	Offshore Installation Manager
OLG	Logistics/Marine Support
OLG/O	Marine Engineering Operations Section
OP	Operations
OSC	On Scene Commander
OSHA	Occupational Safety and Health Administration
OTF	Thai Offshore Well Operations Department
OTF/D	Drilling Operations Section
OTF/E	Drilling Engineering Section
OTF/O	Thai Offshore Well Operations Department
PDT	Product Asset Group
PIC	Person in Charge
PIN	International Asset
POB	Persons On Board
PSB	Petroleum Development Support
QRA	Quantitative Risk Assessment
RTN	Royal Thai Navy
S.V.P. / SVP	Senior Vice President
SAR	Search And Rescue
SBD	Strategy & Business Development Group

SCBA	Self-contained breathing apparatus
SDSV	Senior Drilling Supervisor
SF	Safety Factor
SO ₃	Sulphur Dioxide
SOP	Standard Operating Procedure
SSHE	Safety, Security, Health and Environment
SSSV	Sub Surface Safety Valve
TA	Technical Authority
TSD	Technology & Sustainability Development Group
TSH	Safety, Security, Health & Environment Division
UTM	Universal Transverse Mercator (coordinate system)
VTSS	Hat Yai Airport designation - ICAO
WMS	Well Management System
WWCI	Wild Well Control Inc.

5.0 RESPONSIBILITIES

5.1 DOCUMENT OWNER

The owner shall be the Well Operations Division SVP and is responsible for:

- Issuing the approval of this document and its revisions.
- Leading and demonstrating commitment by endorsing the implementation of this document.
- Giving clear direction on how the document is to be implemented and maintained.

5.2 DOCUMENT CUSTODIAN

The custodian shall be the OWE VP and is responsible for:

- Identifying deficiencies or potential improvements.
- Initiating periodic revisions.
- Maintaining revision history and document status register.
- Advising the document controller of any document changes, including register status.

6.0 INTRODUCTION

In compliance with legislation and moral obligations to protect the safety of personnel and the environment, the corporate team at PTTEP has developed this document to use in support of a rapid and effective response to a well control emergency. This plan outlines the onshore response to an offshore well control incident from a minor situation to extreme case (e.g. blowout). This corporate document can be used as an example for assets to use as a basis for their country or workscope specific plans.

The Blowout Contingency Plan (BCP) is not intended to replace sound judgment and offers only **guidelines** to be followed in the context of the emergency. For illustration this document is written in the context of PTTEP's domestic operations in the Gulf of Thailand however it is intended to be used as a guide for other assets to define/develop a country or location specific BCP.

6.1 OBJECTIVE OF THE PLAN

The aim of any BCP is to enable the swift and effective mobilization internal and external resources to combat and minimize the effects of a blowout. Due to the nature of this type emergency *initial actions* can considerably affect the latter stages of control. Delays of critical actions can cause knock-on effects which would hamper later efforts to control the situation. For example, a minor leak can be easily controlled, but given time it may escalate into a major fire and explosion. Therefore, it may be important to act quickly in the initial stages of the event. The Contingency Plan provides, or indicates, the source of information to enable all those involved in combating the emergency to take the initial, crucial actions required.

The BCP is not a replacement for other manuals/plans such as the PTTEP "Emergency and Crisis Management Standard" or for example in Thailand the "Bongkot Field Emergency Procedure Manual". The BCP is to be used in conjunction with these manuals/plans and bring specific information to handling a blowout.

The BCP does not discuss procedures intended to prevent a loss of well control. The BCP presents only the reactions expected for well control incidents.

6.2 SCOPE OF THE PLAN

The plan also includes the **long-term-activities** required, as a guide to eventual control of the well such as capping operations and/or relief wells.

These procedures begin assumes that immediate actions have already been undertaken to reduce the exposure of personnel to the consequences of the loss of well control (e.g. down manning of non-essential personnel and they have been moved to a safe location, medical attention given where needed, etc.)

The well control event may be the cause or be related to other types of emergencies, such as oil spills. Therefore this BCP plan refers directly to relevant corporate Emergency Procedures and Contingency Plans, rather than including them in this procedure. Users of this plan should ensure that they are familiar with these related documents and corporate policies.

This plan has been kept reasonably concise for ease of use.

6.3 BCP PLAN SUMMARY

Although this BCP covers one operational area as an example (drilling utilizing a jack-up rig and tender assist barge in the Gulf of Thailand), all well control situations require unique equipment, services and procedures to ensure safety, to minimize loss and deal with the problem in an efficient and effective manner. This BCP presents a template and highlights to all assets the need for an operation plan complete with evaluation of the situation and a mobilization scheme.

The most important consideration in the early stages of a blowout, second only to personnel safety, is the mitigation of damage. The BCP includes damage control measures that may be implemented before Blowout Contingency Task Force (BCTF) takes command and a well control team arrives. At times these procedures may conflict with personnel safety which must remain the paramount consideration. These situations require common sense and professional judgment on the part of the person(s) who are directing any mitigation efforts and are in charge of operations.

NOTE: No operation should be undertaken if it involves risk to personnel.

6.4 CONTROL OF A DRILLING EMERGENCY

In most cases, a blowout occurring during operations is the outcome of a period during which difficulties have been experienced in controlling the well. Shallow gas blowouts are exceptions. However, these do not generally require capping or relief wells. Therefore, the only action after a shallow gas blowout has started is abandonment and personnel protection. The figure 1.1 show 3 levels of incident classified.

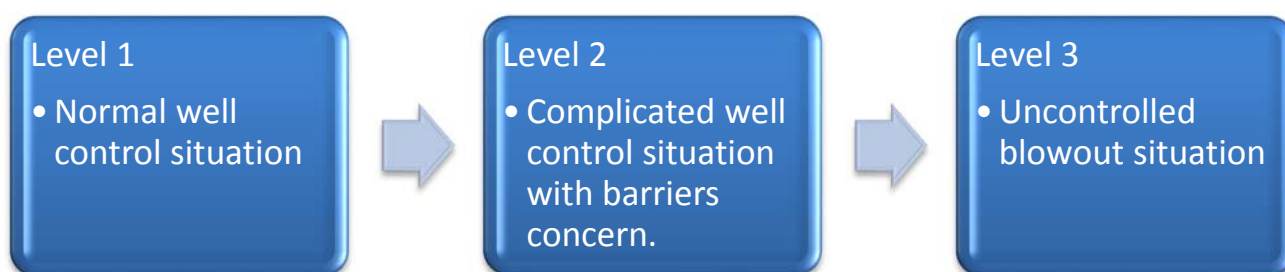


Figure 1 Level of Incident

The escalation period, between "well fully under control", and "well control lost" (e.g. Level 2 incident per definition of Section 1.4 above) during which well control operations are carried out, deserves a special status as regards to onshore management of operations. The escalation often lasts 10 hours, sometimes more, and the decisions taken during this time are often more critical than after the blowout has begun. The reason for this is that up to and until control is lost, one may avoid a potential disaster altogether, whereas after the disaster has already taken place, one can only mitigate the consequences, and often only ineffectively, until major logistics are in place.

In the control operation (example: for the control of a kick) the field team efforts should not be hampered in any way from the primary objective of regaining control of the well.

The decision to move to a Level 2 and thereby assemble the Blowout Control Task Force should be taken before losing control or when loss of control becomes a distinct possibility. Even then, care should be taken not to disrupt the on-going efforts made by the field crews to regain full control of the well.

6.5 MULTIPLE EMERGENCY POTENTIAL

The repercussions of a blowout are likely to be more extensive than any other single event, with possible fire, explosion and associated damage risks. With the potential need for evacuation and oil spillage procedures, the emergency may require the deployment of large numbers of personnel in various teams to deal with specific aspects of the situation. One of the primary actions required in this event would therefore be the allocation of additional space and support in the field for emergency teams, in addition to the Emergency Response Room.

6.6 COORDINATION OF EFFORTS

It should be emphasized that in the case of a blowout occurring on the field, the utmost coordination and cooperation must be established between Drilling Contractors and the Vice President of Drilling Department so as to avoid the redundancy of efforts and to optimize the mutual assistance.

To this end a dedicated telephone line shall be established between the drilling contractors and the Emergency Control Room (E.C.R). It must be emphasized that this line will be used for this purpose only.

6.7 NOTIFICATION

The first responder will typically be the Senior Drilling Supervisor (SDSV). The SDSV after collecting data will notify the **Drilling Superintendent** and the **Drilling Manager** of the Incident. Once the Level of Incident is known, the Drilling Superintendent will assist the SDSV and proceed to respond accordingly. It is common to have kicks or influxes of hydrocarbons and sometimes water during a drilling operation, and these are typically handled by using standard well control procedures. PTTEP has established well control standard procedures for the use of these common well control incidents. There may be cases where small well control incidents escalate into more severe ones. These incidents are known as Level 2 incidents and some examples of these are listed below. If this occurs it may be necessary to consult a well control specialist to assist in normalizing and controlling the well.

6.8 ICS PRINCIPAL

Emergency Response Organization

This plan employs the Incident Command Structure (ICS) system for response to a blowout. ICS is a system of definitions, procedures, job descriptions and instructions for actions to be taken in the event of an emergency. The Incident Command System (ICS) consists of three (3) organizations or teams, and these teams are designed to handle the planning and the response to all well control and blowout incidents specific to PTTEP. The teams are defined as the Emergency Response Team (ERT), the Emergency Management Team (EMT) and the Crisis Management Team (CMT). The Spill Contingency Plan will be launched by SSHE duty in EMT if required.

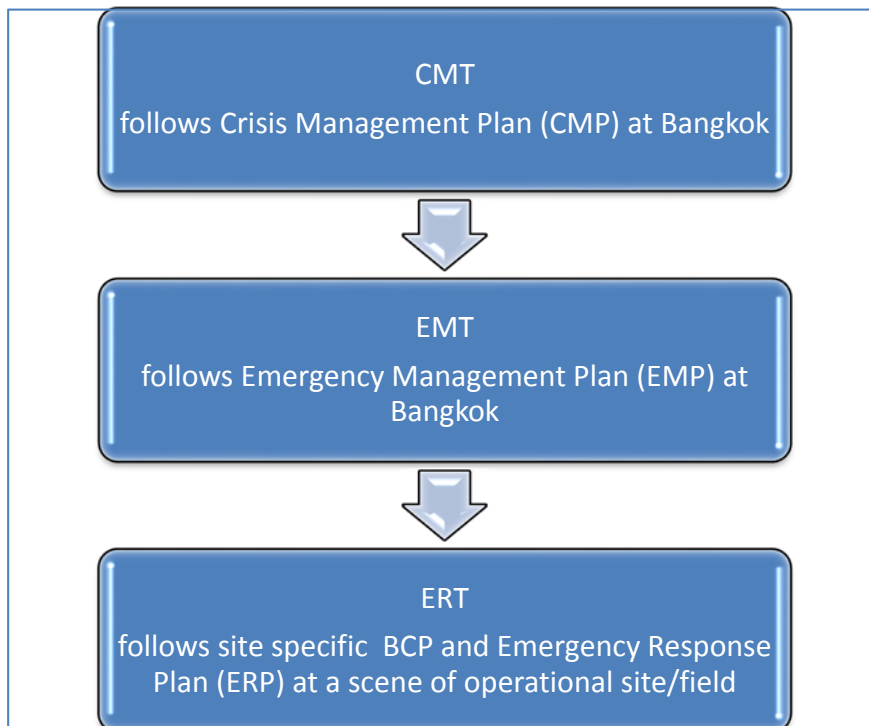


Figure 2: Emergency of PTTEP and crisis management

Emergency Response Team (ERT) on-scene initially and then onshore support teams. Onsite ERT member, comprise the site/field VP/Manager or top authorized person as an on-scene commander as show in Figure 3.

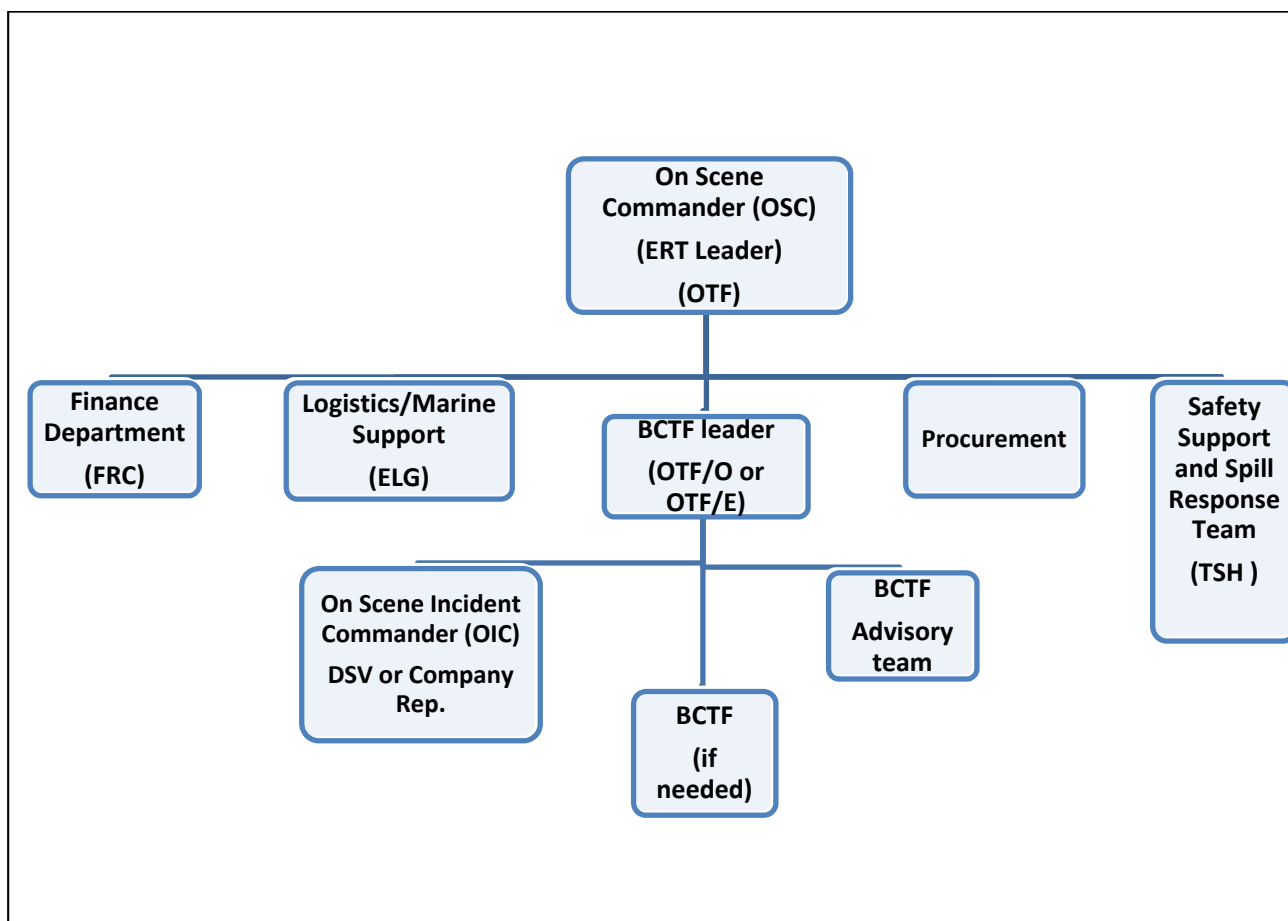


Figure 3: Organization of the ERT

Emergency Management Team (EMT) is involved with an emergency with greater magnitude and major severity in nature or has the potential to escalate and continue for significant period of time until the public may raise concern. EMT member, comprise the top management/authorities in the impact area i.e. the Oil industry Environment Safety Group Association of Thailand (IESG), Royal Thai Navy (RTN), etc., as show in Figure 4.

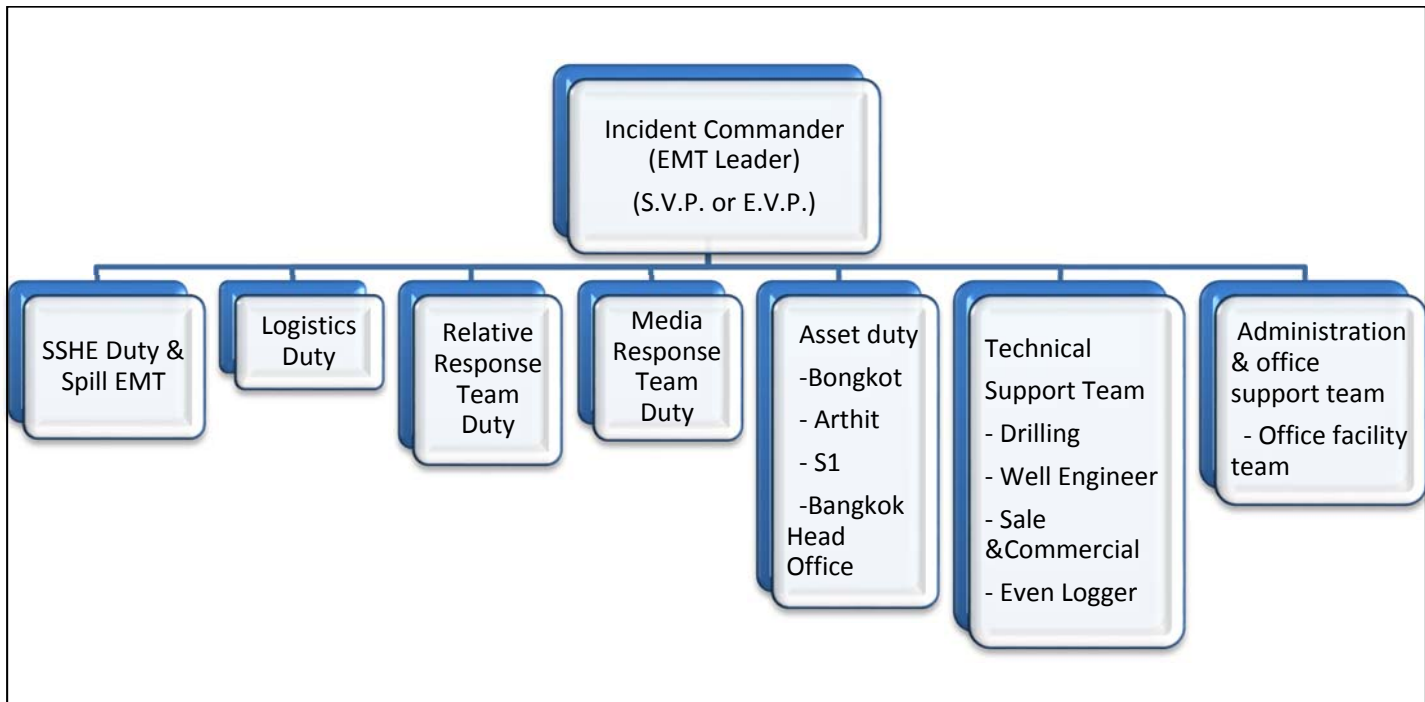


Figure 4: Organization of the EMT

Crisis Management Team (CMT) which is management's role in a complex event (in this plan PTTEP nomenclature will be the Crisis Cell). Corporate CMT member, consists of the top management at the corporate level and other supporting functions as show in Figure 5, their responsibilities and procedure, is defined in the corporate Crisis Management Plan (CMT).

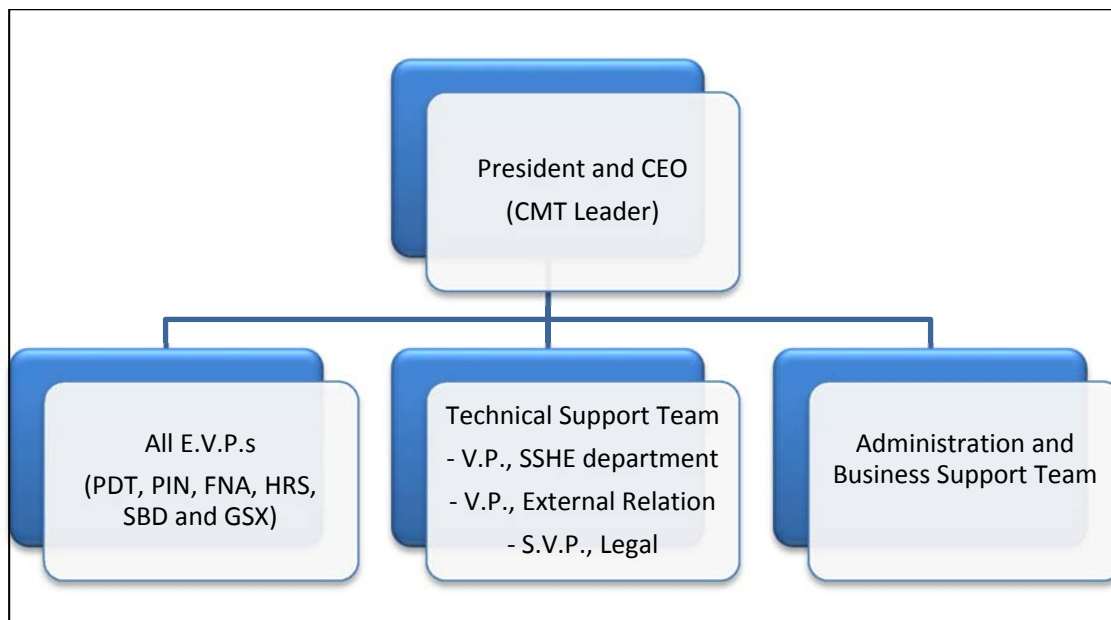


Figure 5: Organization of the CMT

ICS

ICS is a highly structured organizational system developed specifically to manage emergency incidents. It uses a 'command & control' incident management approach to reduce responder risk and to optimize the outcome. It is adaptable, as it allows effective, predefined organizations to function in stressful, high-risk environments. ICS is modular from the top down, which allows it to expand or contract to meet the needs of the task at hand. It has proven to be effective over the past 20 years and has been adopted by many response organizations worldwide. In the USA it is a Federal Law that ICS be employed in emergency response situations (OSHA and EPA).

Response Goals

The goals of the response team are to respond quickly and effectively with a bias toward a structured and unified organizational system. All levels of the overall response teams will follow the decision process described by Figure 6 below:

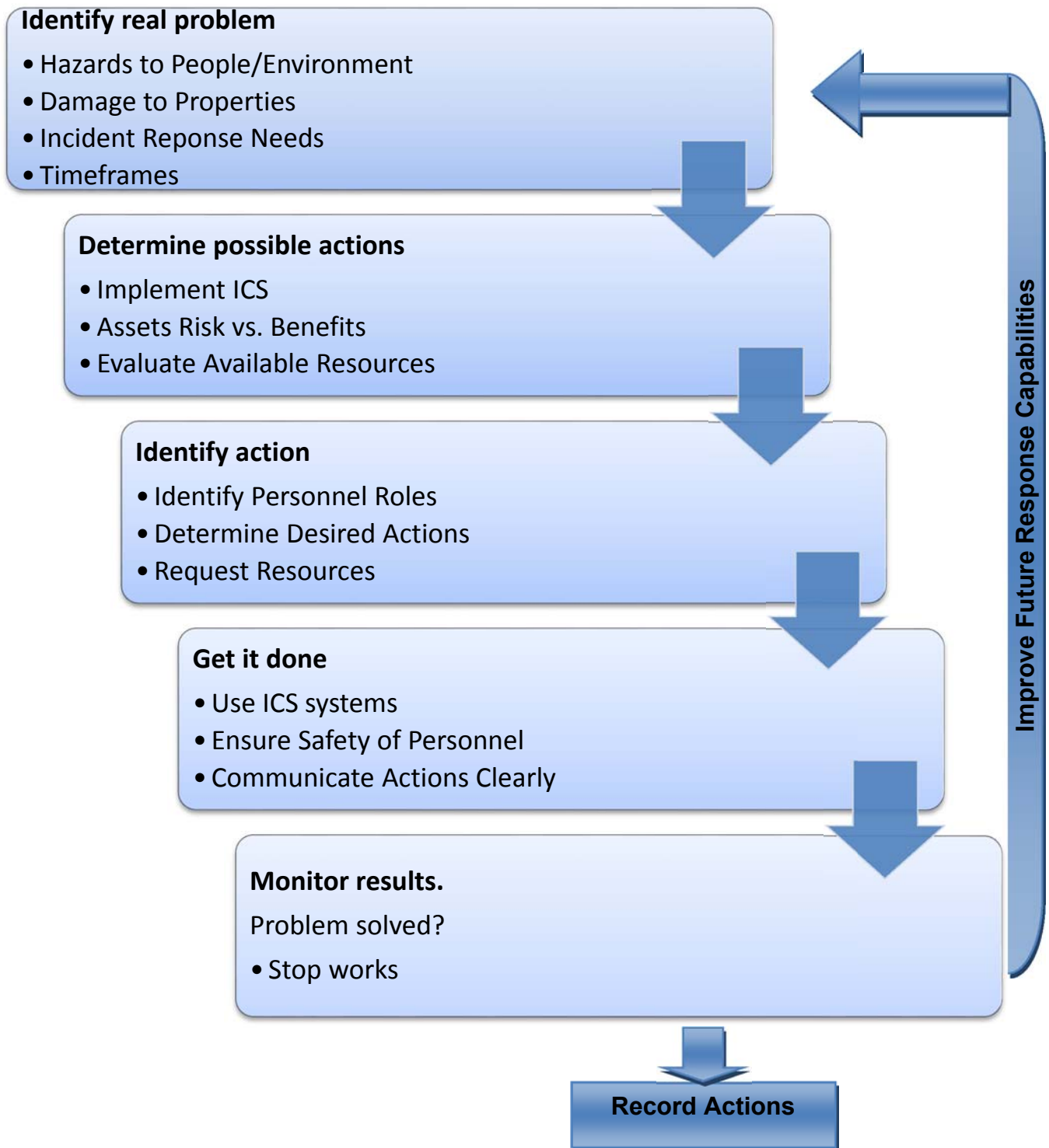


Figure 6: Response Decision Process

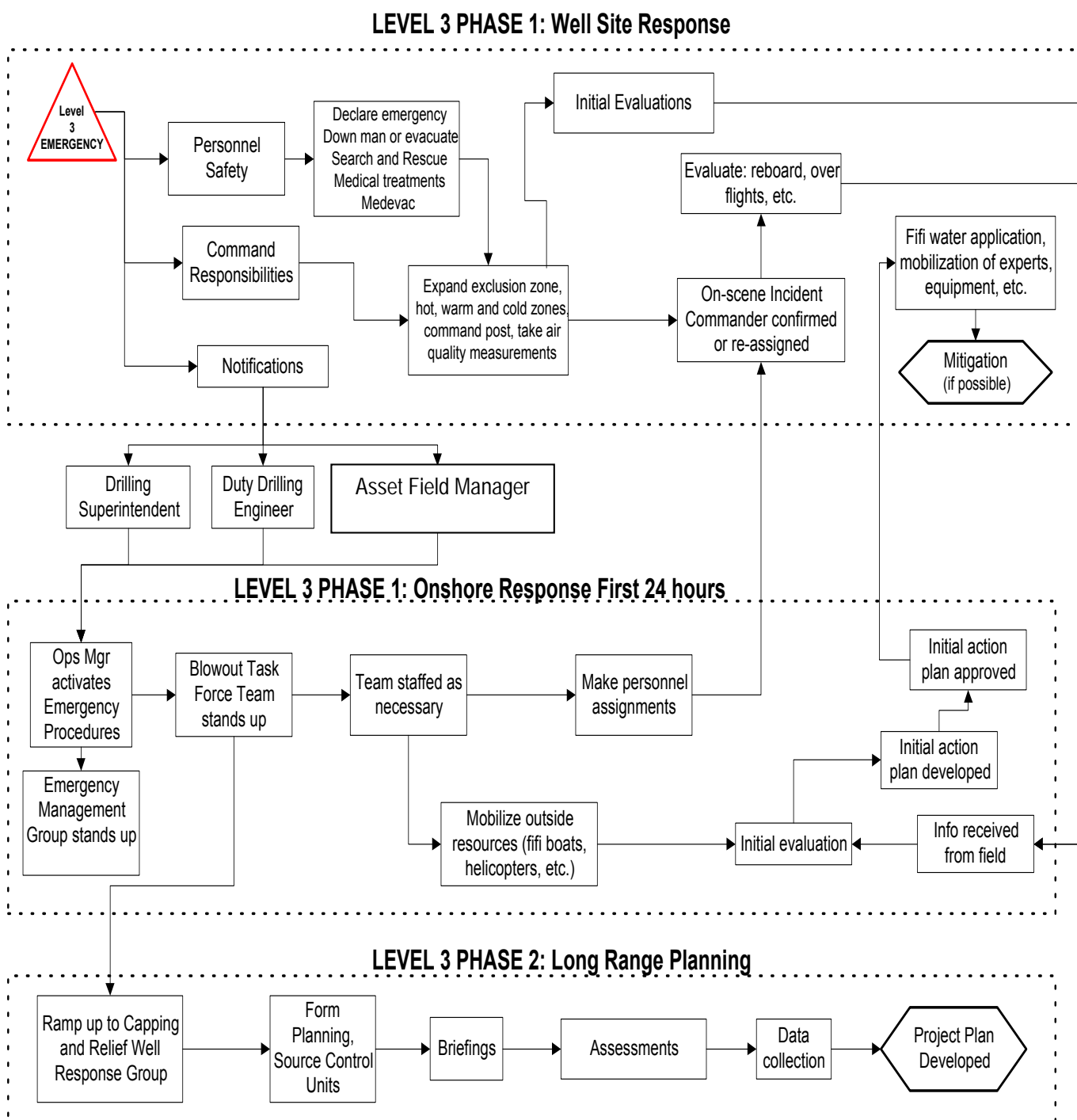
ICS Components

The ICS system depends on ten components to provide the glue that keeps the organization together and functioning properly:

- Common terminology
- Modular organization
- Manageable span of control
- Comprehensive resource management
- Pre-designated incident facilities
- Unified Command structure
- Integrated communications
- Incident action plans
- Common responsibilities for all ICS personnel
- Common Reporting system

ICS Modification for Blowouts

ICS is designed for field activities that are not supported or for blowouts driven by project rules and systems. The first actions to be taken when a blowout occurs must be immediate, which fits the ICS very well. The proactive part of the response will be the control efforts that are best modelled and run as a project, similar to drilling an exploration well or constructing a refinery. Elements of the ICS will however work well for implementation of the project control plan. Therefore, the organizational structures offered in this guideline are modifications of the ICS system and project engineering and design control; e.g., the best of both systems have been utilized.



LWA May-98

Figure 7 Milestone Diagram for Onshore and Offshore Initial Response Action

More detail of this diagram can be found in Section 8.

7.0 NOTIFICATIONS AND INCIDENT LEVELS

This section outlines notifications that are to be made should a well control incident occur. The section described three (3) levels of response, which range from the minor to the very serious. In line with the increasing levels of response, there will be a ramp up of personnel involved. This ramp up of involvement by key personnel is described in the matrix charts shown below:

Affected Personnel Incident Level Drilling	Drilling Supervisor	Drilling Superintendent	Manager, Drilling Operation	VP, Drilling Department	Asset Field Manager	SVP, Operation Support	Duty Officer	VP, Logistics Department	Songkhla Base manager	Executive Vice President	SVP, SSHE Manager	VP, Personnel & Admin. Manager	VP, Reservoir & Exploration Dept.	Blowout Control Task Force (BCTF)
Level 1	X	X	X	N	N									
Level 2	X	X	X	X	X	N	N	N	N	N	N	N		
Level3		X	X	X	X	X	X	X	X	X	X	X	X	X

Figure 8: Drilling Rig Operations Notification Diagram

N = inform only

X = Action

7.1 INCIDENT RESPONSE LEVELS

A three (3) level response based on the severity of the incident is to be implemented. The operational circumstances, the potential for escalation and the potential risk/consequence impact on HSE and Company operations shall be considered in the declaration of the emergency and its level. This approach is outlined in Figure 9.

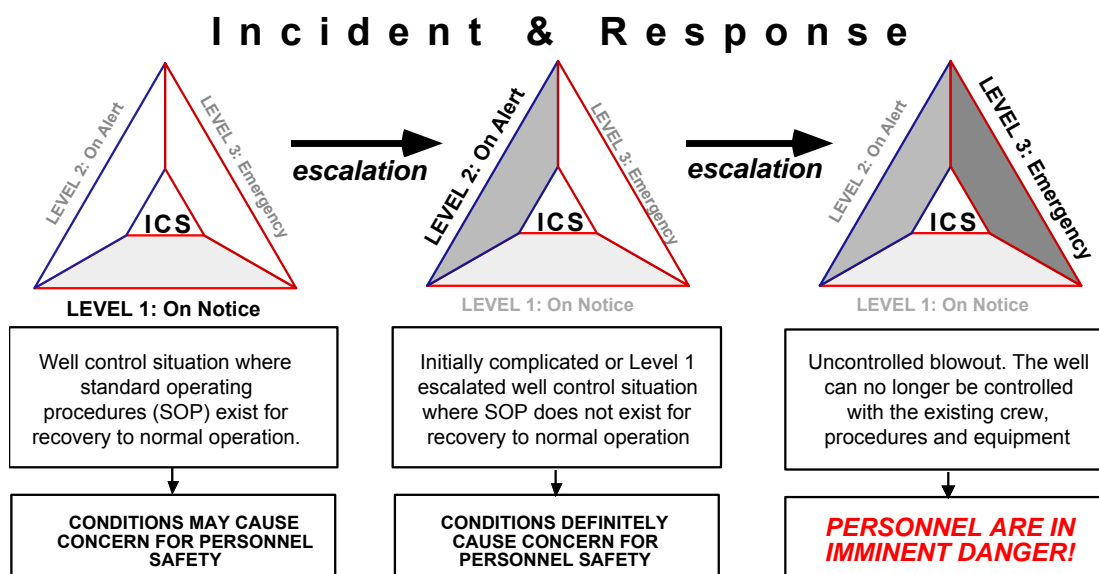


Figure 9: Well Control Incident and Response Levels

The primary components of the response levels are summarized in the following paragraphs:

Level 1 Response (On Notice)

This response is for incidents that on-site operations staff should be capable of handling with standard operating procedures. The incident is of sufficient severity that there is concern for personnel safety and/or potential damage to the well or structure. Level 1 incident classification will be subjective and may be misinterpreted by the on-site staff as routine while it has the potential to escalate to a higher severity level. Notifications are made to immediate supervisors who will approve the classification and proposed control procedures. All level 1 incidents should be appropriately documented and made available for review by other operations staff.

Level 2 Response (On Alert)

This response is for well control or related incidents where there is not a Standard Operating Procedure (SOP) for recovery to normal operations. Control may require resources in addition to the on-site operations staff and/or the use of unfamiliar, more difficult, well control procedures. The incident is of sufficient severity that there is **DEFINITE** concern for personnel safety and/or potential damage to the well or structure. Well control, however, has not been lost. The Level 2 incident classification will be subjective. The Drilling Manager and Area Operation Manager will make the final decision as when Level 1 becomes Level 2. This decision will be based on the risk/consequence for further escalation during non-routine, potentially higher risk, control procedures.

Level 3 Response (Emergency)

This response is for well control incidents where control of the well has been lost. The personnel and structure are potentially in **IMMINENT DANGER**. This would include underground, surface or subsea blowouts. A Level 3 response would initiate a ramp-up to an incident response organization. Resources will potentially be required from outside Thailand. Level 3 incidents have the potential to escalate further during control procedures. Further escalation may include massive pollution, loss of life, serious structural damage or total loss of the MODU or platform and wellhead due to explosion, fire or seabed cratering. Adjacent wells may also be damaged at the surface and seabed, due to fire or flow erosion damage caused by the initial blowout, creating multiple, simultaneous blowouts. Production from other parts of the field may be suspended if the blowout is on a platform that acts as a gathering station for multiple pipelines.

An appropriate response will depend on an accurate assessment of the situation. Therefore, information is essential both in the initial phases and throughout the intervention project. Suggestions are included in each section for information that should be gathered both at the wellsite and from well records.

All situations will require the availability of immediate medical assistance. Additional safety measures and equipment will be required to deal with toxic gas if it is present.

The equipment best suited for intervention varies with each operational setting (i.e., jack-up, platform, floater, etc.). A “standard” firefighting and well control package are specified for the PTTEP Operations setting based on previous experience with such situations. Other equipment and services are specified for support of the intervention project.

7.2 EMERGENCY RESPONSE TEAM (ERT)

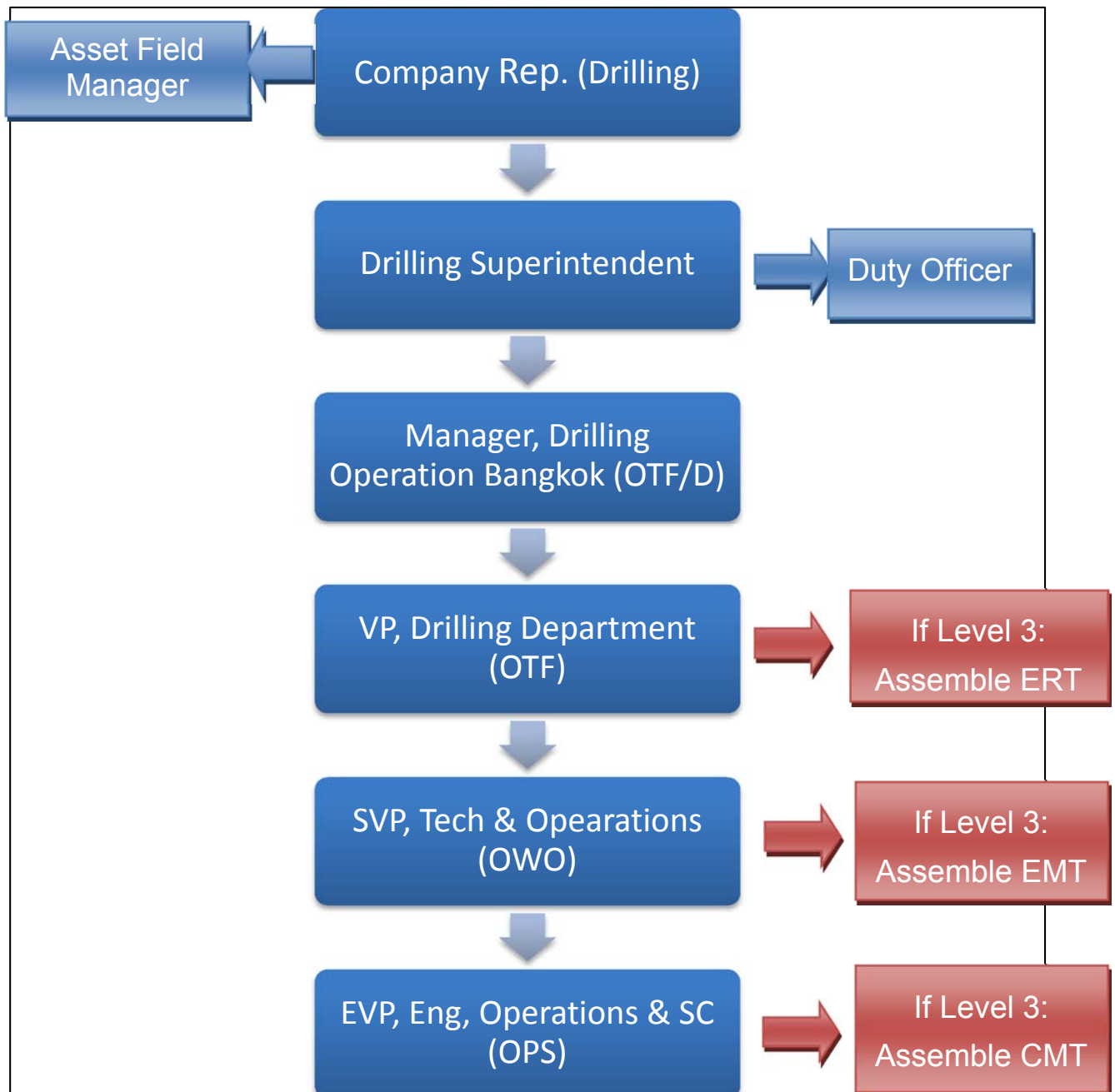
The Emergency Response Team (ERT) will be mobilized by the Vice President (VP) or acting VP. It will be assembled in the Emergency Response Room (room 2948) at the Energy Complex Building A 29th floor. The primary duties of the ERT are to:

- Follow the rules as detailed in the PTTEP Emergency and Crisis Management Standard.
- Take control of the logistics situation.

7.3 NOTIFICATION, ACTIVATION AND ASSEMBLY

The notification charts for personnel involved in the activation of the various response teams are given in diagram below:

a) **Alert Diagram (including out of working hour)**



8.0 INITIAL FIELD RESPONSE ACTION

The response to a well control incident will be according to the appropriate level of the incident (e.g. Level 1, 2 or 3) as defined in Section 2.0. Additionally, the response will be divided into “reaction” and “proactive” actions. The reaction will take place in the first 48-hours +/- of the event. The proactive actions follow the reaction and are designed to bring the situation back to normal operations.

8.1 ON SCENE INCIDENT COMMANDER AND PERSON IN CHARGE

In the situation where a Level 3 emergency has begun certain priorities and actions are required. The most important will be the safety of all personnel, second the facility and support vessels, rig and equipment. The operation will then focus on a solution once initial damage control steps have been taken.

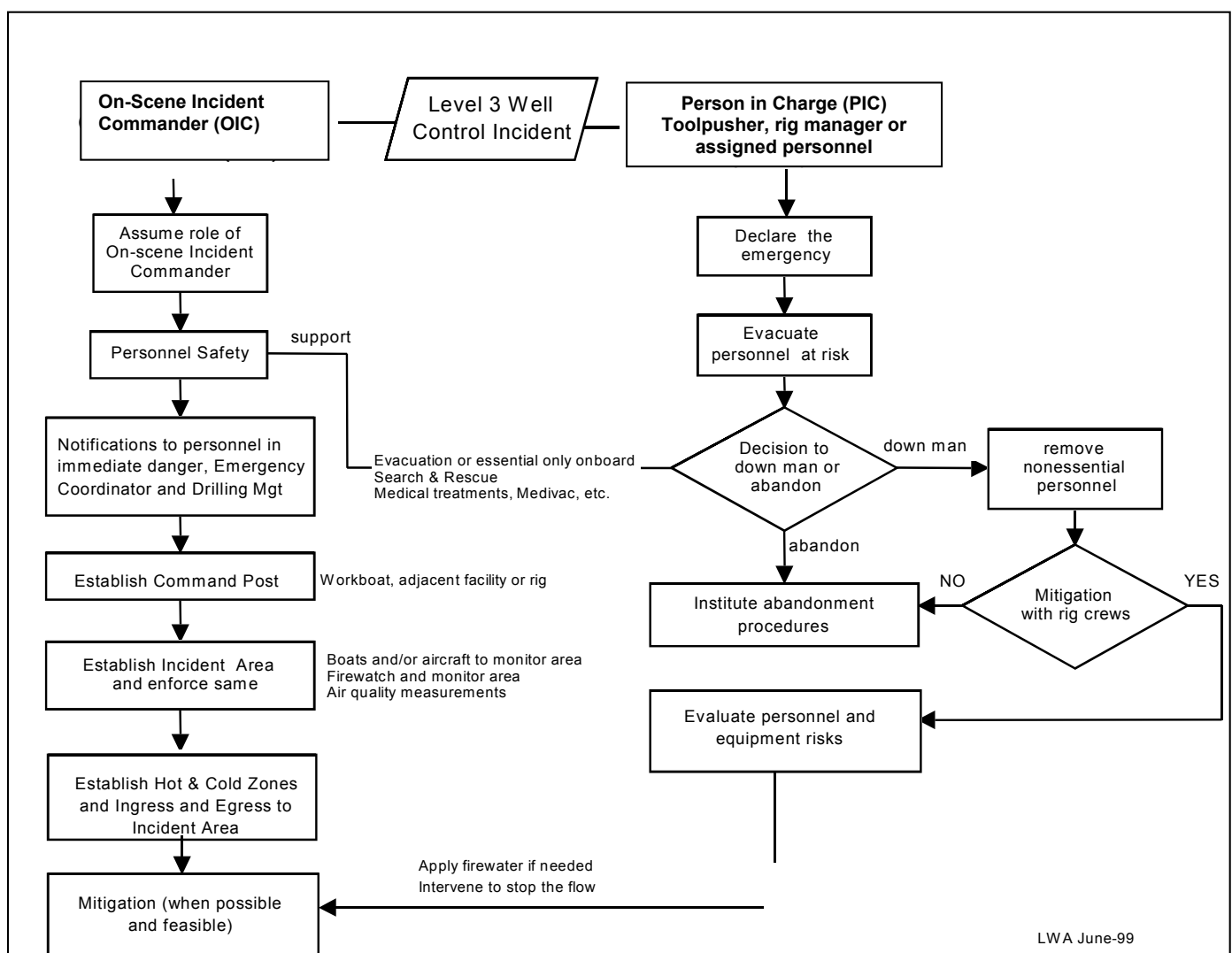


Figure 10 On-Scene Incident Commander and Person In Charge Tasks Flowchart

8.2 PERSONNEL RESPONSIBILITIES AND DESCRIPTION

Responsibilities of Key Off-shore Personnel	Listed below are brief descriptions of the responsibilities of key off-shore personnel who are expected to respond to a well control incident. This plan defines three levels of incident escalation: Level 1 - Notice, Level 2 - Alert and level 3 - Emergency. Level 1, normal and routine well control incidents, are covered by PTTEP's standard operational procedures, and are not addressed here. Responsibilities for Level 2 and Level 3 are outlined below.
<i>Drilling Supervisor On-site Incident Commander (OIC)</i>	Drilling Supervisor is responsible for ensuring that the Drilling Program, Procedures and Policies are carried out by the Drilling Contractor and Third-party Service Companies. The OIC is designated as being in charge of all emergency situations on the drilling rig. He may be advised by the barge captain and rig superintendent (PIC), but the ultimate authority is his and his decision will be final.
<i>LEVEL 2 Alert</i>	The Drilling Supervisor will be responsible for: <ul style="list-style-type: none"> <input type="checkbox"/> determining that Level 2 should be declared, in consultation with the PIC. <input type="checkbox"/> notifying management of a Level 2 well control incident <input type="checkbox"/> activating the appropriate response level on the rig <input type="checkbox"/> maintaining liaison between the PIC and management
<i>LEVEL 3 Emergency</i>	The Drilling Supervisor will continue the appropriate duties above and: <ul style="list-style-type: none"> <input type="checkbox"/> declare the emergency. <input type="checkbox"/> take on the role of OIC (On-scene Incident Commander) until relieved by the Drilling Superintendent or a designee nominated by OTF. <input type="checkbox"/> notify management of a Level 3 well control incident per the notification guidelines <input type="checkbox"/> provide the communications focal point for PTTEP's shore-based management <input type="checkbox"/> coordinate with the Marine Superintendent for standby/supply vessels, fi-fi vessels, helicopters, search and rescue support, shore-based support, support from other rigs in the field, medivac, etc. <input type="checkbox"/> assist in the abandonment, medivac and search & rescue as needed <input type="checkbox"/> monitor the situation and communicate developments to Drilling as they occur <input type="checkbox"/> declare an exclusion zone (see guidelines in Section 4.0) <input type="checkbox"/> assist in asset protection procedures (application of firewater, etc.)

Person in Charge (Contractor Rig Superintendent)	The PIC has responsibility for safety of the drilling rig and the safety, health and welfare of all personnel on board or working in the near vicinity of the drilling rig, including the Drilling Contractor's personnel, PTTEP personnel and Third-party Contractors' personnel.
LEVEL 2 Alert	<p>The PIC will be responsible for:</p> <ul style="list-style-type: none"> <input type="checkbox"/> safety of personnel at all times <input type="checkbox"/> declaring a Level 2 alert <input type="checkbox"/> making notifications to contractor management. <input type="checkbox"/> down-manning of personnel if necessary <input type="checkbox"/> directing the Drilling and Rig crew in performance of their specific response duties while assisting a Drilling Supervisor to control the well <input type="checkbox"/> liaison with the Drilling Supervisor in performance of his duties <input type="checkbox"/> notifying the Drilling Supervisor of emergencies <input type="checkbox"/> suspension of hot work <input type="checkbox"/> securing rig for abandonment if this becomes necessary <input type="checkbox"/> advising Drilling Supervisor when the emergency is over and the return to normal operating status • In case the OIC is incapacitated, he shall assume this role until relieved by PTTEP.
LEVEL 3 Emergency	<p>The PIC will continue the duties above as well as:</p> <ul style="list-style-type: none"> <input type="checkbox"/> declare the emergency after consulting with Drilling Supervisor. <input type="checkbox"/> along with Drilling Supervisor determine a decision of abandonment <input type="checkbox"/> along with Drilling Supervisor determine method of abandonment. <input type="checkbox"/> along with Drilling Supervisor order evacuation of personnel. <input type="checkbox"/> initiate emergency SOP's for abandonment (emergency disconnect). <input type="checkbox"/> call an immediate muster of all persons on board when necessary. <input type="checkbox"/> ensure crew has responded to the alarm. <input type="checkbox"/> Direct and control support vessel and helicopter operations in the vicinity of the rig. • In case the OIC is incapacitated, he shall assume this role until relieved by PTTEP.
Vessel Master (if On-site)	One or more vessels may be tied up to or be in the vicinity of the drilling rig during an emergency or may be dispatched to the site by the marine superintendent. Any vessel in the immediate vicinity or participating in the emergency shall be responsible for the following:
LEVEL 2 Alert and LEVEL 3 Emergency	<p>The VESSEL MASTER has ultimate responsibility and authority for the safety of his vessel and crew. The primary objective of the Vessel Master, in the event of an emergency, shall be to SAVE LIVES by assisting in rescue efforts and/or the application of firewater. If he is notified of an emergency on a drilling rig, he will immediately suspend current operations and offer assistance as requested or as he deems appropriate.</p> <p>He will be responsible to the PIC on the drilling rig, but he may also be directed by the Marine Superintendent or Drilling Supervisor. A partial list of responsibilities are to:</p> <ul style="list-style-type: none"> <input type="checkbox"/> accommodate all drilling rig personnel on a short term basis. <input type="checkbox"/> provide first aid to rescued people as necessary.

	<ul style="list-style-type: none"> <input type="checkbox"/> act as a reserve/relay radio station between base and installation. <input type="checkbox"/> standby close to the drilling rig for helicopter landings and take offs.
	<ul style="list-style-type: none"> <input type="checkbox"/> oversee personnel working over the side; personnel working in/near water <input type="checkbox"/> keep continuous look-out for other vessels that might come near the drilling rig <input type="checkbox"/> assume responsibility for communication with other vessels as the situation demand OTF/O <input type="checkbox"/> transmit messages to air and surface craft <input type="checkbox"/> act as an On-scene Incident Commander until relieved, as directed by management <input type="checkbox"/> maintain communication with the drilling rig, using all visual and audible means available for as long as possible <input type="checkbox"/> monitor the situation and report development to management and the On-scene Incident Commander
Safety Officer/ Technician	Support PIC and OIC as follows: <ul style="list-style-type: none"> • Oversee the practices being used for emergency response. • Participate in decision making process. • Provide advice to Drilling Supervisor and O.I.M.. • Ensure safety equipment is available and working properly. • Make preparations for evacuation, if necessary.
Driller	Support PIC and OIC as follows: <ul style="list-style-type: none"> • Secure well as instructed or based on experience. • Assist Offshore Installation Manager (O.I.M.) and Drilling Supervisor. • Carry out assigned emergency actions.
Barge Engineer, Crane Operator, Electrician, Mechanic, Mud Engr., Radio Operator, Derrickman, Floorman, and Roustabouts	<ul style="list-style-type: none"> • Assist O.I.M. and Drilling Supervisor. • Carry out assigned emergency actions as per SOP. As shown in Transocean Emergency Response Plan.

8.3 GUIDELINES FOR INITIAL RESPONSE

8.3.1 Personnel Safety

In blowout situation the most important consideration is personnel safety. PTTEP operations have developed this document and plan which refer with Emergency Management Plan (EMP). Once the well blowout, all personnel on board need to be checked and accounted. Emergency team such as rescue team needs to be activated. Medivac will be organized if needed. Then activate evacuation plan.

8.3.2 Activate Exclusion Zone

After the rig/platform has been abandoned, the On-scene Incident Commander will be responsible for activating an Exclusion Zone (EZ) for: third party general marine and aviation traffic and any fixed structures and MODUs within the zone. The initial EZ should be a fixed radius around the blowout exit point(s) (some broached blowouts have surfaced several kilometres from the wellhead). The fixed radius should be based on gas dispersion and oil slick modelling for a worst case blowout. Consider:

- Maximum blowout oil flow rates and slick movement on dead calm water
- Lower Explosive Limit (LEL) distances for very stable atmospheric conditions and light wind (< 2 mph).

If modelling parameters are uncertain assume 1 km as a minimum initial radius. Air quality measurement will be used to alter the generalized no-go zones.

8.3.3 Establish On-Scene Command Post

A command post (CP) needs to be established by the On- scene Incident Commander as soon as practical to facilitate coordination of further response activities. If the rig has been partially evacuated, the CP would be the drilling rig, with an observing standby boat acting as a backup in case rapid escalation prevented On-scene Incident Commander communication with support resources. If the rig has been abandoned the CP might be established on a supply vessel, another rig or offshore structure outside the exclusion zone. Good communication equipment is essential between the On-scene Incident Commander, the field support resources and the shore base. The location of the CP may be moved as appropriate at the discretion of the On-scene Incident Commander.

8.3.4 Site Safety

After evacuations and the other initial command structure steps are **taken** by the On-scene Incident Commander, the next issue to be addressed is site safety. Site safety for third parties and responders will be addressed by these steps:

Activate the Initial. Exclusion Zone

This is a pre-determined no-go and evacuation zone designed around a worst case blowout release using gas dispersion modelling tools. Under certain stable atmospheric and wind conditions dangerous concentrations of H₂S gas can travel long distances. For this reason the size of the initial Exclusion Zone should be conservative.

The activation of this zone is a safety measure designed to protect third parties and non-essential personnel from potential exposure while measurements are taken to define a more accurate Exclusion Zone. The activation of the zone will be made by notification to all vessels, aircraft and structures inside the zone. Securing the zone after activation will require several of vessels and/or aircraft.

Define Hot, Warm and Cold Zones

These are safety zones designed to establish levels of increasing potential risk to responders as they move from Cold to Hot. Each zone will have increasing levels of safety requirements before responders are allowed to enter. The combined Hot, Warm and Cold zones will establish the working Exclusion Zone for third parties and non-essential personnel. These zones will be established systematically and should consider the longest reaching hazards first, for example:

- H₂S and/or SO₂ exposure (if applicable)
- gas ignition and explosion with flying debris
- gas ignition and fire
- pool fires
- secondary explosions after primary ignition
- oxygen deficiency
- gas plume hazards on sea surface
- rig instability and/or deterioration
- shifting wind directions and velocities
- blowout intensity escalating
- oil slick movement.

These zones will initially be established by the On-scene Incident Commander in consultation with the Safety Officer (if possible) evaluating each of the potential hazards individually and again as a system. A site specific safety plan must be developed for the team designated to access the zone boundaries, to include support and escape plans. Weather and blowout conditions can change on short notice, therefore these boundaries can also change and must be re-evaluated constantly. If there is uncertainty concerning the potential hazards involved then the On-scene Incident Commander should maintain the Initial Exclusion Zone until relieved trained response person. See also Guidelines, Flowcharts and Checklists section at the end of this chapter.

Define Access and Egress Routes

OIC is responsible for setting the boundaries for the Hot, Warm and Cold Zones. Routes into and out-of the zones must be established for response personnel for re-entry and emergency escape. Generally the access and egress routes are best made in the upwind hemisphere. If approach is made in a vessel current and waves should also be considered if an oil slick is to be avoided or if power failure of the vessel might cause it to drift down wind into the danger zone. The preferred course of access may be to approach at 90° angles to the wind/current direction. All hazards must be considered, however, before finalizing the routes note that the egress route may change during the course of a work period, due to changes in conditions and should be monitored continuously.

Exclusion Zone Safety Procedures

Site specific exclusion zone safety procedures must be established for all personnel entering each of the three zones. The On-scene Incident Commander in consultation with the Safety Officer and Toolpusher (as applicable) and shore base supervisor would define these procedures. If re-entry is to be considered after an abandonment, the OIC must consider the following:

- The need for entry
- Evaluate risks for entry team
- Develop tasks for entry team
- Develop contingency plans and escape means for various scenarios, e.g.:

- Operational “Site Safety” meeting with all concerned
 - discuss personnel safety
 - - emphasis on buddy system
 - set objectives of re-entry- emphasis on escape and contingencies,
 - equipment checks for hot and warm zone participants
- Issue Personnel Protection Equipment For Staff In Each Zone (if needed)
 - SCBA (if appropriate)-
 - heat fire resistance clothing-
 - hearing and eye-protection (with heat shielding)-
 - hand held communications-
 - air quality monitoring devices-
 - head, hand and foot protection
- General Site Security and areas to avoid:
 - closed areas- highly contaminated areas (gas, oil, etc.) g
 - as concentration (high LEL, H₂S, etc.)
 - onsite toxicants and chemical exposure (caustic, acids, etc.)
 - site procedures for access control and personnel monitoring
- Site safety will be a particularly important issue if the decision is made to allow essential personnel to remain on the facility to execute mitigation procedures (pumping, firefighting, etc.) or if firefighting vessels are to be deployed in the warm zone to spray water after the rig has been abandoned. If the facility is destroyed or the perceived danger is high, the site safety issue should be left to the Level 3 Source Control Team

8.3.5 Asset Protection & Damage Control

After the site safety issues are addressed, asset protection and damage control may be addressed by the On-scene Incident Commander. Listed below are a few procedures that may be considered:

- ESD initiation (if appropriate)
- Blowdown of site hydrocarbon inventory
- Shut-in of wells and pipelines feeding facility
- Secure adjacent wells in well bay (if possible)
- Firewater Application, deluge systems (if appropriate), fire water application from marine vessel(s) to minimize ignition hazard or to cool structure and/or adjacent wells

Some of the steps listed above may be part of the facility operations standing procedures in a Level 2 emergency (example: simultaneous operations on a joint drilling and production operation). They are mentioned here to alert the reader to the situation where they are not standing procedures and may be considered in the overall action plan taken by the on On-scene Incident Commander. It is important to maintain control over any firefighting vessel that might be deployed to spray water on the rig. The captain and crew of the vessel must be debriefed and fully understand the potential dangers of escalation and safety procedures that must be followed before they are deployed into a potentially dangerous situation. Non-essential crew should be removed before entry into the Hot or Warm Zone.

All safety equipment and breathing systems must be checked before entry.

8.3.6 Rig or Structure Re-entry by Initial Response Team

Re-entry of the rig or structure where a surface blowout is underway should not be attempted by the Initial Response Team without approval from PTTEP management. The case of search and rescue (SAR) may be accepted, but only then after a detailed safety/rescue plan is in place for the responders. For all other purposes (e.g., assessment or mitigation) the Initial Response Team should wait for the Level 3 professional response team to arrive and develop a detailed proactive plan of action.

8.3.7 Blowout Control Response Actions

Blowout control response actions should not be attempted by the field personnel unless approved by PTTEP management and only then after a credible operation plan has been devised along with a site safety and escape plan. In cases where the blowout occurred rapidly with no chance for off-site support, the rig/structure should be secured and abandoned. Blowout control response would wait for the Level 3 ramp-up and a proactive plan to be developed by the Source Control Team. Circumstances where the ECT might attempt blowout control actions would be where an escalation has occurred gradually from a Level-2, Incident, the rig has been down manned, and the shore based support team has already been activated. In this case, if the ECT and the support team both feel an immediate control attempt has a high probability of success, the safety risk is low, further rapid escalation risk is low and a site safety plan has been developed then control attempts may be initiated. An underground blowout that has a low probability of breaching would be an example.

***** WARNING *****

- In no case shall the response team be subjected to unreasonable risk. At all times during this initial phase 1 period, safety of personnel will be the number 1 priority. The rig crews should not be expected or asked to perform potentially dangerous tasks that they have not been trained to perform.

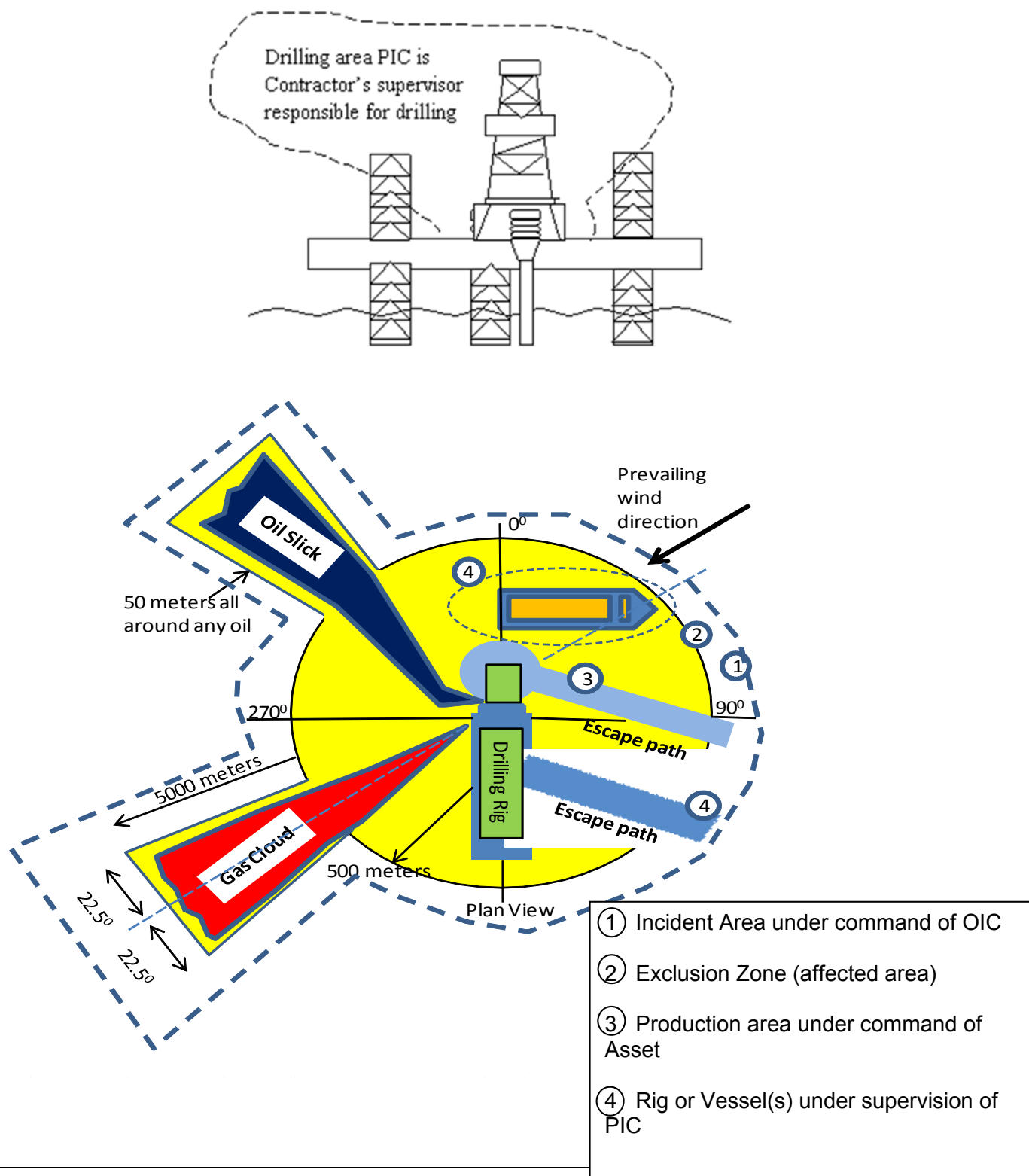
Level 3 - Phase 1 on-site blowout control response actions will be specific to company approved policy and: (1) the type of rig or structure (e.g., rig or platform rig); (2) the circumstances of the blowout (e.g., surface, on fire, underground, potential risk for escalation); (3) the operation at the time of the incident (e.g., drilling related, workover related, testing related or production related); (4) potential for sabotaging future proactive control plans if an immediate attempt fails, and (5) the local environment at the time of the incident (e.g., night/day, weather, fire, pollution, available resources, willingness, training level and skill of crew).

8.4 ON-SCENE INCIDENT COMMANDER & PERSON IN CHARGE TASK LISTS

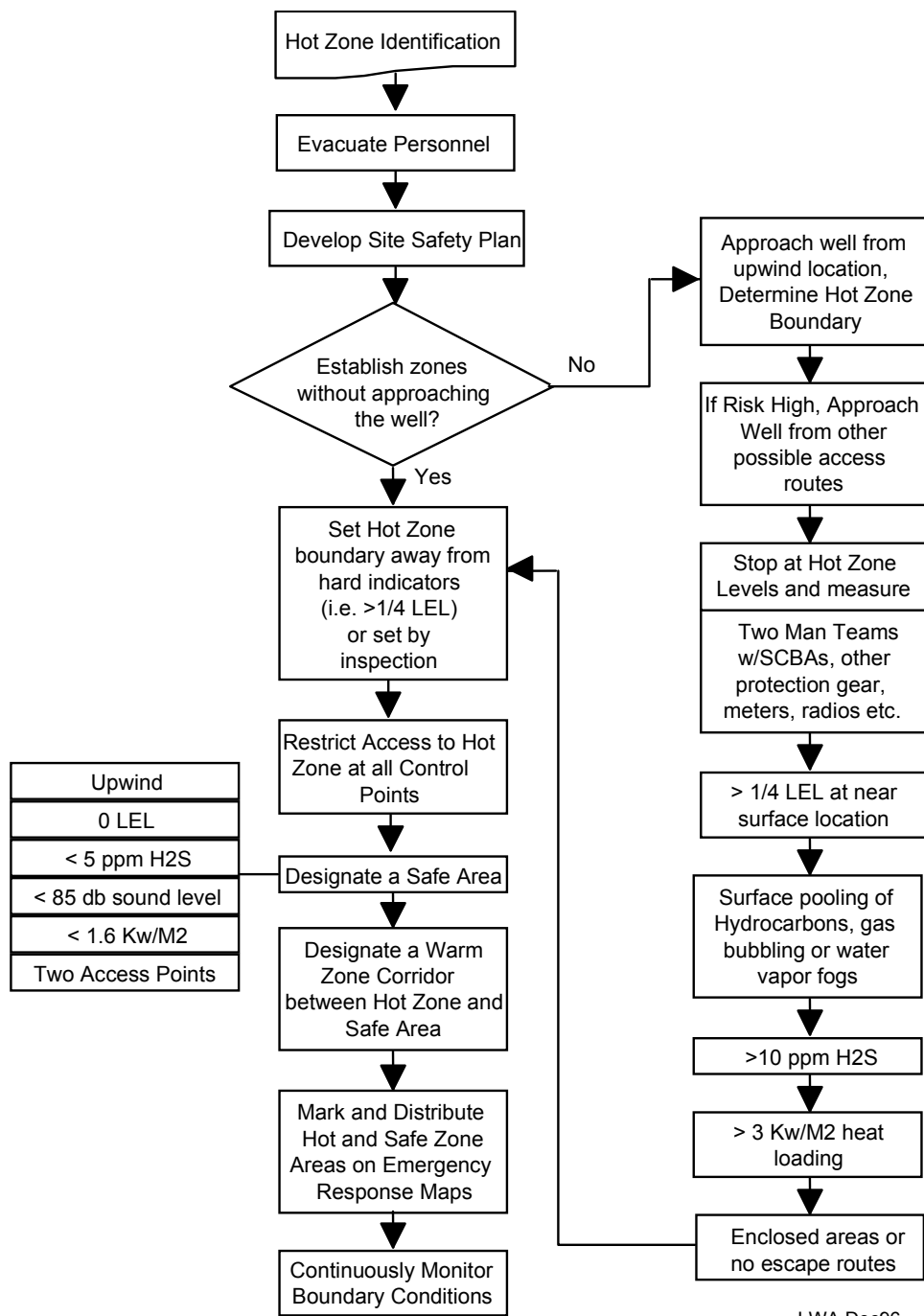
Command Organization and Responsibilities	
Level 3 - Phase 1	
Initial On-scene Incident Commander and essential crew only	
Item	Action or Consideration
1	When the decision is made to abandon the rig or platform, the PIC will maintain command of the evacuation operation until his charges have been rescued and is relieved of his duties. During this time, close liaison will be maintained with the PTTEP Representative, whos duties will be to assist the PIC as directed and to coordinate off site notifications and support. After the rig or platform has been abandoned the PTTEP OIC will assume command of further response operations. There can be only one man in charge, if the pre-designed On-scene Incident Commander cannot assume his command one must be appointed.
2	Make notifications as per the notification diagram in section 2.
3	Appoint deputy On-scene Incident Commander and team leaders (ex: toolpusher is deputy, barge engineer becomes team leader, etc.).
4	Establish essential personnel roster. Appoint support staff and outline responsibilities (drillers, electrician, mechanic, medic, etc.).
5	Set up command post (standby boat, control room, radio room, etc.) Man communication equipment, keep channels of communication open for important relays (e.g. essential communications only).
6	Establish Incident Area, activate Exclusion Zones for general aviation and marine traffic enforce the same.
7	Establish preliminary Hot Zone boundary.
8	Hold initial briefing meeting with team members - address personnel safety and medical issues - search & rescue necessary? - mitigation and or damage control objectives - re-board for evaluation - refer to BCP plans and checklists
9	Assign monitoring responsibilities - begin fire watch, organize fly-by and or marine observation.
10	Begin reporting sequences
11	Mitigation when possible (firefighting, etc.) and <i>ONLY</i> with approval of management.

8.5 HOT ZONE IDENTIFICATION

If a level 3 event occurs (like a blowout) certain key personnel are expected to take charge of their respective areas. In the drilling scenario the Companyman becomes the On-scene Incident Commander (OIC) in charge of the overall incident area. The rig or, any vessel, will be commanded by a Person In Charge (PIC) who has ultimate responsibility for his respective area. The diagram below shows the various areas of responsibility:



8.5.1 Hot Zone Identification Flow Chart



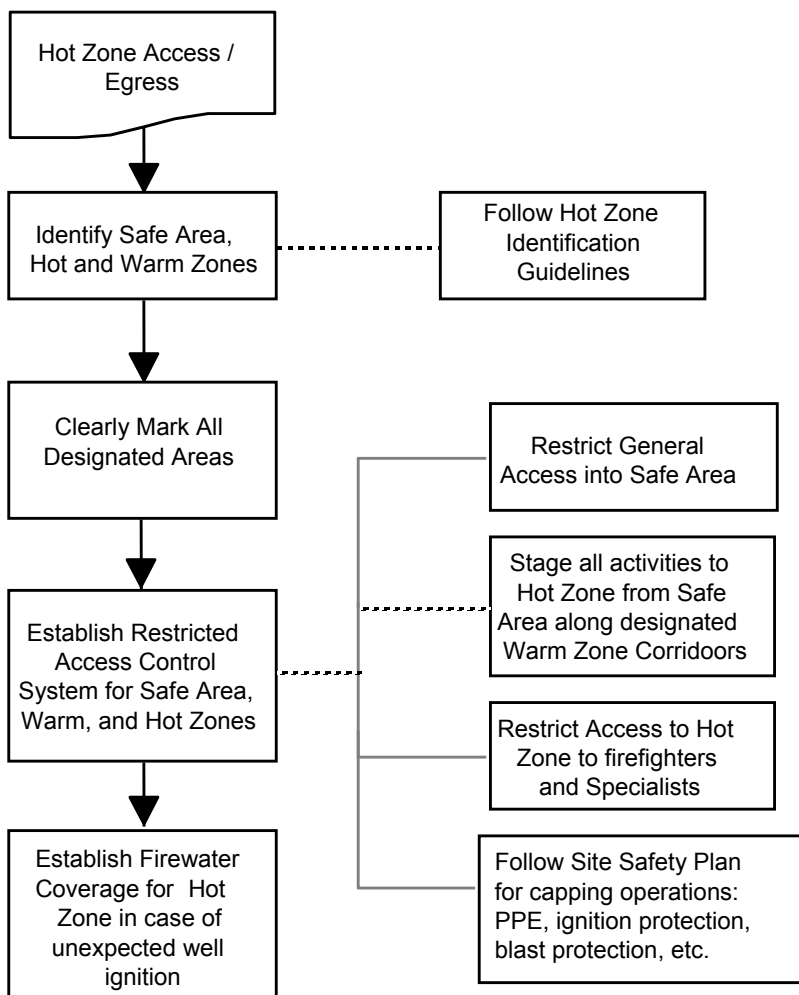
8.5.2 Hot Zone Identification Checklist

HOT ZONE IDENTIFICATION	
Level 3 - Phase 1	
Initial On-scene Commander and essential crew only	
Item	Action or Consideration
1	A "SITE SAFETY PLAN" is required before wellsite work can start. This plan is developed and implemented by the On-scene Incident Commander after initial evacuation of personnel.
2	The "Hot Zone" boundary must be realistically based on presence or the anticipated presence of an explosive mixture (LEL levels), rain of hydrocarbons or H ₂ S and is principally controlled by wind direction but is influenced by the leak rate and location as well as the direction of the flow.
3	On burning blowouts the "Hot Zone" will likely be set on radiant heat limits and smoke avoidance. Wind direction also has considerable impact in Hot Zone boundaries. Some fires do not burn clean and product can exist in the presence of a fire, therefore item 2) and 3) must be considered together.
4	Generally the hot zone will be set by inspection and not from a quantitative analysis. This will be revised as time goes on and will be monitored carefully throughout the project.
5	If the "Hot Zone" boundary is set by actual measurements, it will be done by two men with SCBAs. They should approach blowout using LEL meter, H ₂ S meter, dB meter and Radiant Heat Meter (if available) and check levels down wind of the well area. Initial approach should be from an upwind direction.
6	The boundary of the HOT zone is defined as when first indication is seen of either: <ul style="list-style-type: none"> • >1/4 LEL level (1% concentration of hydrocarbons in air) at any near surface elevation (ground level or standing on top of a truck). • surface pooling or streaming of liquid hydrocarbons, surface gas bubbling or hydrocarbon and water vapor fogs (restricted visibility and explosive vapor) • >10 ppm H₂S • >90 dB noise level • Over 3 Kw/m² heat loading or practically the point where exposed skin cannot sustain exposure without protection for more than a few minutes. CONTINUED....
7	When measuring parameters, approach problem well from any possible access route (including those located downwind) and repeat this process.
8	Where possible, set Hot Zone boundaries away from these hard indicators (ex: 1/4 LEL) at good control points. CONTINUED....
9	"Hot Zone" shall be restricted to well control experts or designee of the On-scene Incident Commander and shall be allowed in the zone on a permit only basis and only for a prescribed and defined task. Buddy system will be maintained at all times and cover of water provided for each when appropriate.
10	Manpower with radios from drilling rig crew, safety and production can be used at these defined "Hot Zone" control points to restrict access into the "Hot Zone". Downwind "Hot Zone" boundary must be tightly controlled and continuously monitored as variable winds can quickly change the boundary. Some access routes should be blocked to prevent accidental entry.
11	The "Safe Area" or "Cold Zone" location is based on the "measurable" Hot Zone boundaries, available work areas and access and wind direction.

12	The safe distance seen in the downwind approach of the "Hot Zone" boundary is then used as one guideline for setting the "Safe Area". Additionally dispersion modeling can be used with the measurements taken to help predict downwind conditions if wind is blowing across blowout out to sea.
13	The "Safe Area" is not a contour like the "Hot Zone" but is a dedicated staging area for control efforts for blowout. Access to areas inside the "Hot Zone" must be from "Safe Area". Other alternate paths into "Hot Zone" are blocked.
14	"Safe Area" should be accessible from two directions.
15	"Safe Area" restricted to essential personnel with proper protective equipment.
16	"Safe Area" should be in area with 0 LEL, <5 ppm H ₂ S, <85 dB sound level and <1.6 Kw/m ² heat loading.
17	Mark the designated "Hot Zone" and "Safe Area" on the available Emergency Response Maps for distribution and all procedures.
18	As the well and wind conditions change, the "Hot Zone" boundaries will shift. The "Safe Area" could also be moved. An example would be shifting boundaries after well ignition.
19	The "Warm Zone" is the route between the "Safe Area" and the "Hot Zone". Control indicators (LEL levels, H ₂ S, radiant heat etc.) are continuously monitored within the "Warm Zone" at the entrance to the "Hot Zone".
20	The "Warm Zone" is restricted to essential support personnel only.

8.6 HOT ZONE ACCESS & EGRESS

8.6.1 Hot Zone Access and Egress Flow Chart

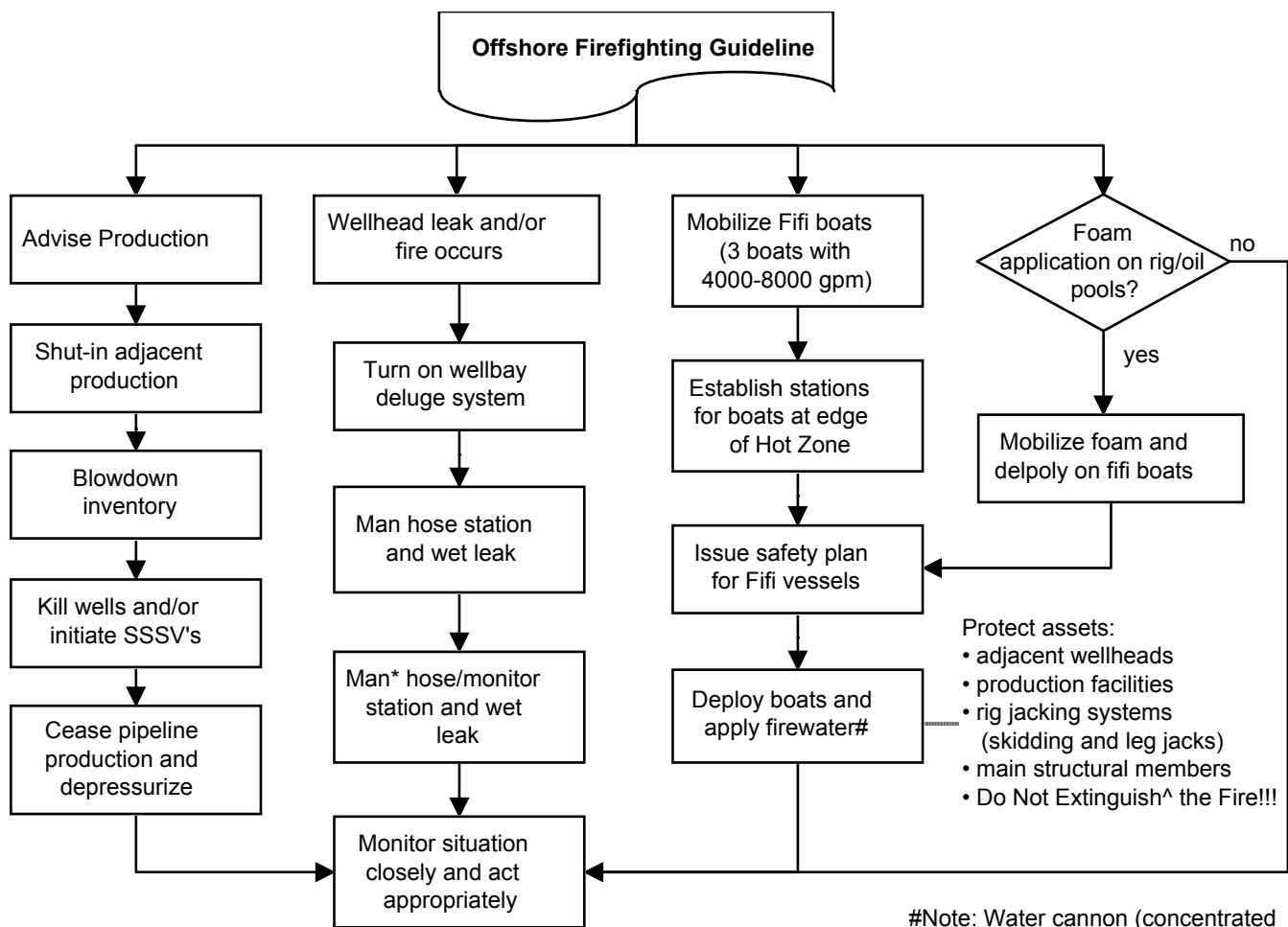


8.6.2 Hot Zone Access and Egress Checklist

HOT ZONE ACCESS and EGRESS ROUTES	
Level 3 - Phase 1	
Initial On-scene Incident Commander and key personnel from the site crew	
Item	Action or Consideration
1	On-scene Incident Commander to define "Hot Zone" boundaries and "Safe Area". This defines "Warm Zone" along access route between the "Hot Zone " and "Safe Area".
2	Stage all activities to the "Hot Zone" out of the "Safe Area" along the designated and continuously monitored "Warm Zone".
3	On-scene Incident Commander to establish access system at "Safe Area"
4	On-scene Incident Commander to maintain control points at all possible access routes and/or block the access
5	On-scene Incident Commander to allow access to "Hot Zone" only along the Warm Zone" route by strict control.
6	Only experienced firefighters and blowout specialists are allowed within the "Hot Zone" under strict access coordination with Safety and the OIC.
7	Offshore rigs may have significant blast hazard inherent in design. Enclosed spaces filled with explosive vapor may explode if well ignition occurs.
8	"Hot Zone" approach lanes must be set up with fire water coverage to protect men from fire or unexpected well ignition. Shield safe havens may be needed.
9	Approach lanes to and within "Hot Zone" must be upwind and clearly marked
10	"Hot Zone" approach lanes must be aligned straight away from rig structure corner to limit potential blast exposure from unexpected ignition. Make use of available blast cover.
11	Personnel working in "Hot Zone" may will require Decontamination areas at edge of "Hot Zone" with communications.
12	Personnel must check in and out of Warm areas
13	Access must be tightly controlled if well is not burning. A minimum of exposed personnel must be maintained as explosive vapor cloud ignition can occur naturally at any time.
14	Vapor clouds have the capability to throw debris great distances if ignition occurs. Debris away from the ignition source can be thrown great distances and therefore present a grave danger to personnel.

8.7 FIREFIGHTING AND ASSET PROTECTION

8.7.1 Firefighting and Asset Protection Flow Chart



^Note: If the fire is extinguished an explosion hazard will exist that may be more dangerous than the fire itself. Pollution may be reduced if the well is left on fire.

*Note: Once water is directed to the affected area lock in monitor and remove personnel. If the danger to putting a man in the wellbay area for firefighting is high it should not be done.

#Note: Water cannon (concentrated steams) can cause extensive damage from impact and flooding. Therefore one should avoid direct contact to weak members (windows, walls, etc.) and onto open hatches if possible.

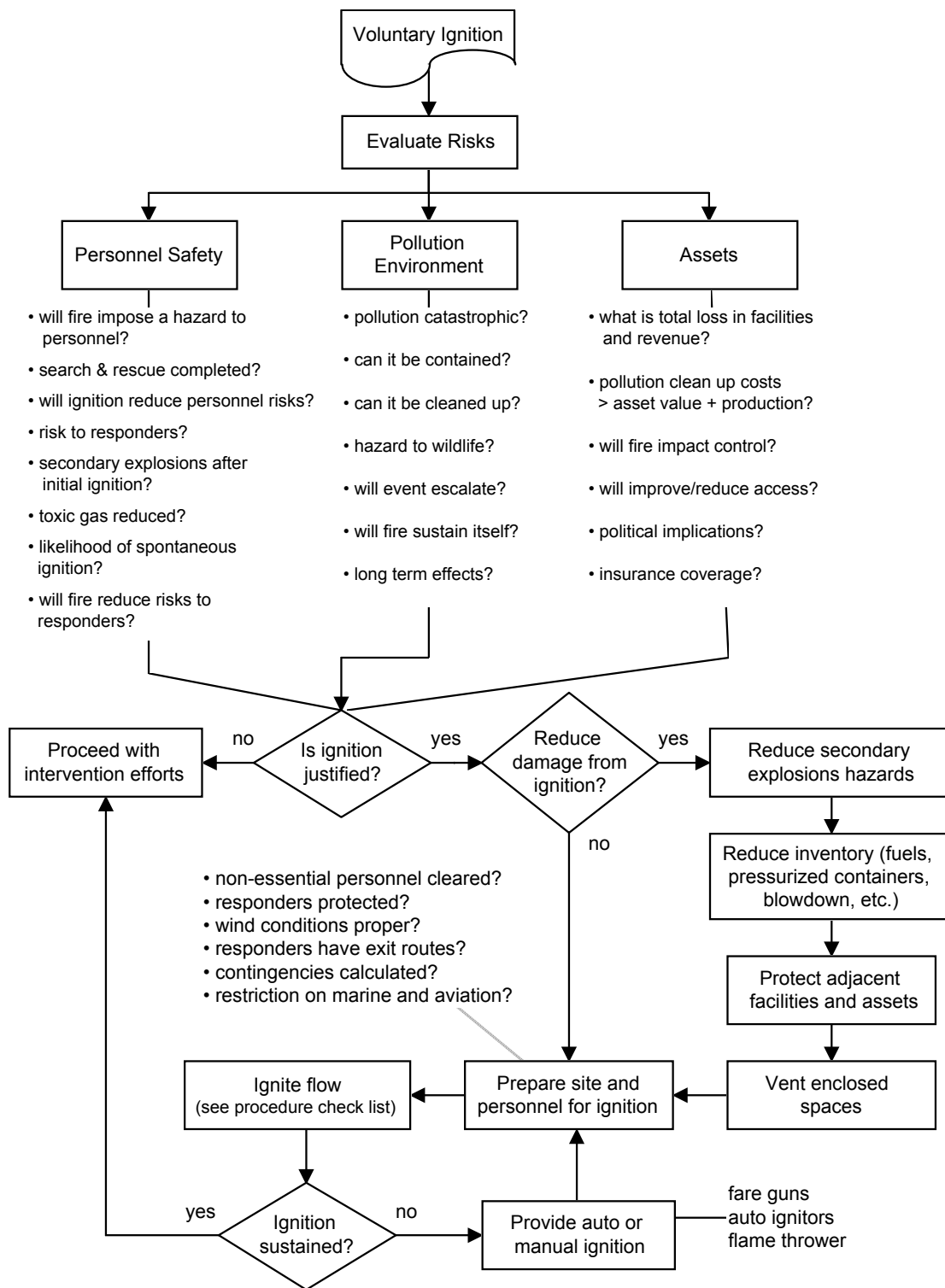
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8.7.2 Firefighting and Asset Protection Checklist

FIREFIGHTING & ASSET PROTECTION	
Level 3 - Phase 1	
On-scene Incident Commander & Company Representative	
Item	Action or Consideration
1	Initial firefighting and asset protection should start at the rig and expand to the locally available Firefighting Units. This list assumes that there is a pressure fed well fire.
2	Turn on rig sprinkler system and use fire hoses to keep fire away from personnel if necessary during evacuation (if rig is equipped and feasible).
3	Establish "Hot Zone" & "Safe Area"
4	Establish Hot Zone Access & Egress Control
5	Mobilize locally available mobile fighting equipment, field boats with firewater capability (three boats with 4000 to 8000gpm each are needed)
6	Local firewater capability must not wait for blowout specialists to arrive as fire damage to the structure, surrounding wells and process equipment must be quickly limited.
7	All of the required firefighting equipment (outside of vessel fifi) is currently located in Europe or the USA and must be mobilized to the site.
8	Crew should hook up to rig deluge system if possible & activate if rig is on fire.
9	<p>Spray water to protect adjacent wellhead areas and production equipment.</p> <p>Spray water to protect rig equipment and jacking hydraulics to assist in skidding drilling package.</p> <p>Blow down all production lines and displace with nitrogen or water if possible.</p> <p>Confirm that all adjacent wells are shut-in on subsurface safety valve and surface valves. If possible kill offset wells.</p> <p>If possible, dump or pump out all stored combustible fluids on rig or nearby production facilities (diesel, methanol, glycol). Displace storage vessels with water or nitrogen.</p> <p>Remove any stored chemicals or pressurized containers. Even fire extinguishers can blow up if they get too hot.</p> <p>Spray water only on those areas that are too hot. Do not extinguish fire.</p>

8.8 VOLUNTARY IGNITION PROCEDURE

8.8.1 Voluntary Ignition Flow Chart



See ignition guidelines below

8.8.2 Voluntary Ignition Guideline and Procedure Ignition Criteria

Voluntary Ignition Guidelines and Procedures Ignition Criteria

The following sections discuss purposeful ignition of a blowout. If significant concentrations of oil, toxic gas (H_2S , SO_2 , etc.) or pollution are resulting from the blowout, consideration should be given to ignition of the well. The following is suggested criteria, equipment and procedures for ignition. Under certain conditions it may be necessary to ignite well flows which do not contain H_2S . This is typically a difficult decision based on safety and environmental factors such as pollution and the perception that ignition will reduce risks and pollution. This decision can involve legal and insurance related issues. If significant concentrations of H_2S are resulting from the blowout, consideration may have to be given to ignition of the flow. This is especially important if the well is situated in or near navigable waterways (inland waters), near populated areas or in extremely sensitive environmental areas.

NOTE! Unless ignition of the well flow will obviously reduce the immediate danger to the public or personnel, the OIC in charge should consult with ERT before making the decision to ignite the well.

Ignition can be a very dangerous operation, especially if oil slicks surround the structure or appreciable oil accumulates on and in the rig. The ignition of any blowout by untrained or under-equipped personnel should only be attempted if no other means exists to protect the safety of personnel in the vicinity. Further, proper equipment to do so safely must be available. If it is apparent that the hydrogen sulfide gas being released may endanger the health and safety of the public or wellsite personnel or may cause serious environmental contamination, the OIC in charge (or personnel designated by the OIC in charge) will ignite the gas cloud.

In some instances it may be prudent to ignite well flows which do not contain toxic concentrations of hydrogen sulfide. This is typically a difficult decision based on safety and environmental factors and often involves legal and insurance related issues. Unless ignition of the well flow will obviously reduce the immediate danger to the public or wellsite personnel, the OIC in charge, or designated representative, should consult with Regional Management before making the decision.

The decision to voluntarily ignite a blowout carries with it major implications. The worst being that the situation becomes worse rather than better. The greatest concern is that ignition will cause severe structural damage or, in the worst case, will damage adjacent wellheads causing additional blowouts and fires (multiple wells in an inland water situation). Further, this may cause the well control effort to be orders of magnitude greater than if a single well was blowing out but not on fire. The decision to purposefully ignite a blowout can only be done if it is thought that human life can be saved as a result or major pollution avoided. There will be other considerations that enter into the decision and are outlined below.

When H_2S is emitted from a blowout the decision becomes somewhat less complex due to the eminent danger to life. What must be considered in the ignition of an H_2S flow is the by-product of the reaction, SO_2 . Sulfur dioxide is also a toxic gas that causes irritation of the upper respiratory tract, inflammation of mucous membranes, dry throat, cough and burning of the eyes with concentrations of 5 ppm to 100 ppm. High SO_2 levels or extended exposure can lead to death by asphyxia, chronic pneumonia or bronchitis, increased sensitivity to SO_2 and possibly cancer. The outcome is that fire does not remove the danger but it alters the characteristics. The downwind side of the fire still poses a danger in the form of SO_2 and should be isolated from access by personnel and vessels. In certain situations, where H_2S levels in the flow are not extreme, the SO_2 released due to burning may be manageable. Ignition in these cases may be the best alternative where extreme risk to the lives of personnel is at stake. Under most conditions, it is not advisable to automatically ignite an H_2S flow unless lives are in danger.

Once the decision to ignite is made, the decision then turns to the method. Although a remotely operated ignition system similar to that used to ignite a flare is an alternative, the risk of an unintentional or premature actuation due to panic makes this method undesirable. In most

situations the best alternative may be the use of a flare gun or other similar device to ignite the flow from the upwind side. This may be risky due to the limited access caused by the H₂S.

To assure proper consideration is given, the matters listed below should be examined:

- evacuation of all personnel from the area or facility.
- assure that no one or no equipment is working within a minimum of a two (2) kilometer or 1.2 miles downwind radius of the site.
- close valves or other devices which may provide a possible fuel source or migration path for a fire or flow.
- evaluate wind and weather conditions to ascertain whether the situation can change to endanger personnel either on the wellsite or at an adjacent installation.
- the nature of the flow, cause, probability of increased severity and assessment of methods to stop the flow through short term efforts
- will conditions permit a safe assessment without putting the evaluation team in undue risk
- whether ignition using a flare gun is possible from a safe distance, i.e., strong prevailing winds away from the firing position, H₂S free atmosphere from which to work, available cover from a flashback and clear access for escape.
- the range of the flare gun and whether access to the wellsite within this range is safe and possible in view of the presence of H₂S and heat radiation from the fire after ignition. Proceed if these conditions can be met.
- can one clear all personnel, aircraft, vehicles and equipment from within a 2 kilometer (1.2 mile) radius except for the vehicle required for a firing base.
- is an approach to the site from upwind side while monitoring H₂S levels available.
- once ignition has taken place no attempt to approach the site should be made until the situation stabilizes and conditions permit access with reasonable safety and under strict supervision of experts.

A basic decision tree is presented in the flowchart shown in section 8.8.1 to aid in the decision making process that must take place before igniting an H₂S flow. An alternate method using a helicopter may be considered. In this case a flare gun is the recommended method to ignite the flow.

Ignition Equipment

The following equipment will be available and on-site for use by the ignition team personnel:

- 2 - Flare gun with two dozen flares (one for ignition and one for spare).
- 2 - 500 ft. fire resistant retrieval rope.
- 1 - Portable Combustible Gas Detector.
- 1 - Portable H₂S meter and/or personnel monitors.
- 3 - Adequate number of SCBA's for ignition team members (min. of 3).
- 1 - Marine vessel with communication equipment (two-way radio, etc.).

Specific Ignition Procedures

The OIC in charge or alternate will ensure that wellsite personnel are evacuated to a safe location upwind of the well. The OIC in charge will then proceed with the following ignition procedures:

- The OIC and a designated assistant (either drilling supervisor or safety consultant), backed up by one or two designated wellsite personnel, will comprise the ignition team.
- The backup member(s) will be positioned by a radio equipped vehicle at a safe distance from the gas/oil release. They will standby to rescue the primary ignition team with the retrieval ropes, if necessary.
- The assistant of the team will carry an explosimeter and will continuously monitor the area for explosive gases.
- The OIC in charge will carry the flare gun. (Flare shells are to be carried in a separate container - not in your pocket).
- All personnel not required to operate the vessel used to make the approach should have been removed. Once within a safe range a single man should stand behind a protective barrier (vehicle, etc.). Escape from the area should be made with haste due to the possibility of secondary explosions and falling debris.
- The ignition team will determine the hazardous area (10% of lower flammable limits) and establish safe perimeters. Once this is determined, the ignition team should move to the upwind area of the leak perimeter and fire a flare into the area. If the leak is not ignited on the first attempt, move in 20 to 30 meters parallel to the well and fire again. If trouble is incurred in igniting the gas, attempt to fire a flare at 40 to 90 degrees to each side of the area where you have been firing. If adequate equipment is not available or ignition is not possible, the toxic leak perimeter must be established and continued until the emergency is secured.
- Escape from the area should be made with haste due to the possibility of secondary explosions and falling debris.

8.9 PERSONNEL SAFETY & VICTIM MANAGEMENT CHECK LIST

Date : _____ Time : _____ Filed by : _____ Title : _____

IMMEDIATE VICTIMS	YES	NO	REMARK
• All personnel/contractors accounted for?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Triage/treatment/transport functions established?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Medical facilities identified/notified?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Transportation to specialty hospitals?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Police notifications?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Victims identified?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Victim list complete/verified?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Victims' families notified?	<input type="checkbox"/>	<input type="checkbox"/>	_____
SEARCH AND RESCUE			
• PTTEP personnel rescue?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Public agency rescue?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Full protection for rescue/back-up personnel?	<input type="checkbox"/>	<input type="checkbox"/>	_____
PUBLIC			
• Evacuation of public required?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Medical assistance required?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Local agencies notified to assist?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Weather or other factors to potential affect the isolation area?	<input type="checkbox"/>	<input type="checkbox"/>	_____
CONTROL (MINIMIZE IMPACT)			
• Special diagnostic and care facilities identified?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Employee and family assist/counselling identified?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Human resources support identified?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Personnel Center activated?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Liaison with Authorities underway?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• All communication between sites OK?	<input type="checkbox"/>	<input type="checkbox"/>	_____

RESPONSE	YES	NO	REMARK
SPILL MANAGEMENT			
• ECG/EOC activated?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Source identified?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Leak/release stopped?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Release continuing?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Downwind evacuation?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Ignition sources eliminated?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Released ignited/burning?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Perimeter/exclusion zone established?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Exposures?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Command Post established?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Unified command with responding agencies?	<input type="checkbox"/>	<input type="checkbox"/>	_____
CONTROL & SUPPRESSION			
• Incident Action Plan developed?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Control method identified?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Control method risk v. gain agreement?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Foam applied to suppress flammable vapors?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Foam applied to burning pool fires?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Foam applied to burning pool fires?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Fire allowed to burn out?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Water fog applied to exposed wellheads and equipment?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Fuel control accessible?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Suppression strategy developed?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Suppression strategy acceptable for safety?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Expected release duration: _____ days/hrs.			
STATUS			
• Extinguished?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Still burning/size?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Contained?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Exposures?	<input type="checkbox"/>	<input type="checkbox"/>	_____

RESPONSE	YES	NO	REMARK
SAFETY			
• Site Safety Plan completed?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Hazard monitoring completed?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• PPE requirements defined?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Decon area(s) established?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Site Security plan completed?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Site Security enforced?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Air quality monitoring underway?	<input type="checkbox"/>	<input type="checkbox"/>	_____
HAZARDOUS MATERIALS			
• Affected facilities notified?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Gas characteristics known?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Toxic or hazardous?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Plume model run?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Exposure areas identified?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Site control in effect to protect response workers?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Evacuation or affected-area-control initiated?	<input type="checkbox"/>	<input type="checkbox"/>	_____
WELL CONTROL			
• Well control be established field/rig?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Capping and or firefighting required?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Technical well-control ex-perts on-scene at command post or tele-linked?	<input type="checkbox"/>	<input type="checkbox"/>	_____
• Relief well required?	<input type="checkbox"/>	<input type="checkbox"/>	_____

9.0 BLOW OUT RESPONSE PLAN INTRODUCTION

The Blowout Response Plan is cover to the long-term action once the immediate emergency is blow out in Level 3 accident. The Blowout Response Plan will be under Blowout Control Task Force (BCTF) member.

The Blowout Control Task Force is a team within the ERT. Decision to mobilize the Blowout Task Force is taken by the ERT Leader and the BCTF leader will report to the Incident Commander.

The BCTF will be independent of normal activities to minimize the impact on routine operations. There will always be single point leadership of the various components of the Task force to ensure that they are working in a coordinated manner.

The Task force will generally consist of two or more teams:

- Well capping team
- Relief well team.

9.1 EMERGENCY RESPONSE TEAM -ERT

The Emergency Response Team (ERT) will be activated and mobilized by the Vice President or acting VP and assembled in the Emergency Response Room (room 2948) at the Energy Complex Building A, 29th floor. The ERT **shall follow the guidelines and procedures** as detailed in the PTTEP Duty Officer and Emergency Management Plan. The ERT is charged with the full responsibility for the control operation and shall take control of all aspects of the logistics situation.

Notification of the Emergency leading to the ERT mobilization will be done as per section 2.3, Notifications.

9.1.1 Authorities and Responsibilities (1st Priorities Assigned to ERT)

A summary of action and liaison responsibilities for the ERT during a Blowout Emergency is given here below. This just highlights the main duties. For the additional tasks the reference manual is the Duty Officer and Emergency Response Group manual. ERT organization chart as per Figure 1.

ERT Member	Action	External Liaison Responsabilités
On-Scene Commander (OSC) ERT Leader (EDL)	<ol style="list-style-type: none"> 1. Ensure that all appropriate ERT disciplines have been contacted and have a representative. 2. Maintain permanent contact with site. 3. Mobilize additional resources if needed. 4. Assess the number, type and identity of casualties, extent of damage to facilities. 5. Nominate a Blowout Control Task Force leader. 6. Liaise with EMT leader. 	Site of Emergency. Specialized Contractors in Blowout Control.
Manager, Drilling Operation (EDL/O)	<ol style="list-style-type: none"> 1. Receive Control of BCTF from Emergency Controller. 2. Coordinate and Organize the Blow Out Control Task Forces. 3. Notify the Blow Out to the rig owners and all sub contractors. 4. Contact Blowout Advisor. 5. Start to organize the BCTF. 	Rig owners, Capping Co., Blowout Advisors.
Logistic/Marine Support (OLG)	<ol style="list-style-type: none"> 1. Liaise with the Logistic Base Superintendent in Songkhla (OLG/O) and establish the position of the marine vessels and helicopters that can be made available. 2. Ensure readiness of logistics in nearby PARTNERS subsidiaries in the event they have the necessary equipment and personnel 3. Obtain Weather Forecast. 4. Contact and liaise with the shipping contractor, marine contractor and helicopter contractor. 5. Arrange general transport. 6. Arrange transportation for specialists. 	Marine Weather Services Service Vessels Owners Lloyd Helicopter GCNK Logistics Singapore Equipment Suppliers Transport
Safety, Security, Health, & Environment Division (TSH)	<ol style="list-style-type: none"> 1. Obtain POB information for the site concerned and dispatch to all ERT members. 2. Advise the Emergency controller on health, safety and 	<ul style="list-style-type: none"> - Police, Thai Navy, DMF. - Fire fighting resources, Contractors

	<p>environmental matters.</p> <ol style="list-style-type: none"> 3. Establish fire-fighting resources that can be made available for support. 4. If relevant implement the Spill Contingency Plan. 5. Obtain immediate assistance from other companies as required. 6. Establish liaison with DMF. 	
Personnel Administration (HHR)	<ol style="list-style-type: none"> 1. Organize the administrative support required by the BCTF. 2. Supply housing to outside experts joining the BCTF. 3. Takes care of visa / work permit problems (if any) 4. Supply additional medical support. 5. Support Relatives Response Team 	
Asset Finance Department (FAC)	<ol style="list-style-type: none"> 1. Organize the finance officer on duty support required by the BCTF. 2. Support Risk Management Information 	
Procurement (POC)	<ol style="list-style-type: none"> 1. Organize the procurement officer on duty support required by the BCTF. 2. Support Procurement Information and Process 	

9.2 BLOWOUT CONTROL TASK FORCE- BCTF

The BCTF is a team composed of PTTEP, Partners and external personnel dedicated to the well killing operations.

The different leaders in the BCTF will be nominated by the Operation Support.

9.2.1 Notification, Activation and Assembly

The BCTF is the operational entity that is exclusively dedicated to the blowout control operation.

Some main principles must be kept in mind in organizing the BCTF:

- Personnel assigned to the BCTF from within PTTEP must be relieved from all other duties.
- Personnel who might have been deeply affected by the trauma caused by the blowout should not be assigned to the BCTF in any case, and should be replaced by other personnel.
- The best experts must be chosen to perform the job within or outside of PTTEP, such as partners. There should be no hesitation in obtaining assistance from whatever source necessary.
- It is the responsibility of both the Operations Manager, Chief Engineering Operation, and the DSV to gather the best team possible, as quickly as possible, to deal with the situation.
- The BCTF leader will first organize the BCTF with the Operations Unit people and complete it thereafter with external assistance such as PARTNERS personnel.
- A secretarial assistance should be organized for the BCTF in order to keep an accurate and detailed log of events. The ERT will organize this.
- A specific cost controller (from Finance Department) must be assigned to the BCTF to follow up the costs related to the capping and relief well operations.

**THE BCTF MUST BE GIVEN ALL AVAILABLE MEANS TO
FULFILL 100% OF ITS OBJECTIVE:**

RECOVERING THE CONTROL OF THE WELL

The Manager, Drilling Operation is nominated by the Technology and Operations Division as the Task Force Leader.

In case he is not available the Technology and Operation Division will then designate another Task Force Leader.

The basic philosophy adopted by PTTEP Operations and adhered to, will be to create two separate teams inside the BCTF:

- The Capping Operations Team.
- The Relief Well Operations Team.

The main objective of the BCTF Leader (OTE/O) will be to simultaneously start preparation of both activities, so as each one may start independently of the other one and in the shortest possible time scale.

The BCTF leader will then appoint the leaders for the Capping and Relief Well teams. He will submit the names of the above persons to the Operation Support for his approval.

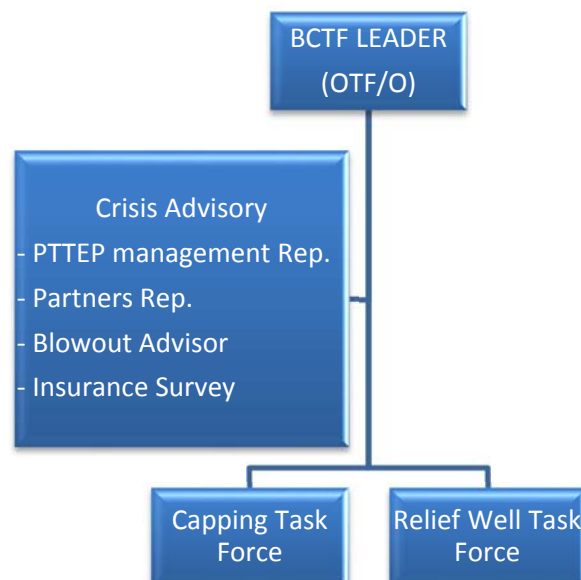
In addition and in parallel to the BCTF a Crisis Advisory is set up. The Crisis Cell will be led by the BCTF leader. A composition of the Crisis Cell is shown in the Fig below.

9.2.2 General Organization of the BCTF

The basic philosophy adopted by PTTEP Operations and adhered to is to create two (2) separate teams inside the BCTF.

They are

- The Capping Operation Team
- The Relief Well Operation Team



Note : The Blowout Advisor will be mobilized by the BCTF leader.

The Insurance Advisor will be mobilized through PTTEP

9.3 BCTF MEMBERS JOB DESCRIPTION

The following pages outline the “Job Specifications” for various critical members of the BCTF. They intend to fulfil two purposes:

- To outline the requirements for various members of the BCTF so that a fast and effective search can be made within or outside PTTEP for the best personnel to assist in dealing with the emergency.
- To assist in briefing the personnel as they arrive at their desired location, enabling a speedy assimilation into the organization.
- Any personnel assigned to the BCTF will be relieved of all other duties for the duration of the emergency.
- The selection of the people to be assigned to the BCTF should be as follow:

- Operational Staff having the required level of knowledge and competency shall be assigned to the blowout task force as much as possible. This is motivated by their good knowledge of the specific field problems.
- However, as per EMP, OTF/O judgment any PTTEP personnel deeply affected by the trauma caused by the blowout shall be replaced by other available engineers, PARTNERS for instance.
- Specific tasks must be assigned to people having already gained practical field experience. Therefore the BCTF leader shall not hesitate to call for PARTNERS specialists, if none are available in PTTEP staff.

9.3.1 The Crisis Advisory

Crisis Cell Member	Origin	Responsibilities
BCTF Leader	Shall be Chief, Drilling Operation (OTF/O).	<ul style="list-style-type: none"> - Coordinates the various operations and takes the experts advice. - He is responsible for the operations carried out. - He shall report to the Incident Commander and obtain his approval for major decisions.
Partners and/or Management Representative	A Expert with good leadership and technical background. He must have a good knowledge of blowout control operations.	<ul style="list-style-type: none"> - Strictly an advisory function: as PARTNERS representative he shall provide the best advice possible so as to assist the local team in decision making. - He is not entitled to take any technical leadership during the operations nor to give any orders or instructions
Blowout Advisor	<ul style="list-style-type: none"> - Boots & Coots IWC or - Any reputable Consultant. 	<ul style="list-style-type: none"> - Advisory role only. - Due to his high competence in blowout engineering he will advise on the best well control strategy. - He shall assist the BCTF leader in making the decision on relief wells matters. - He shall only give advises to PTTEP management. <p>His assistance will be of particular importance in the liaison with the insurance representative to their full cooperation and assistance.</p>
Insurance Surveyor	Insurance Company Representative	<ul style="list-style-type: none"> - Consultation Information only.

9.3.2 Blowout Task Force Teams

Capping Operations

Capping Team Member	Origin	Responsibilities
<p>Capping Operation Leader</p> <p>Drilling Superintendent</p>	<p>PTTEP staff must have :</p> <ul style="list-style-type: none"> - Good knowledge of the overall structure and systems on the particular installation (Rig, Platform). - A perfect knowledge of the well status - A perfect knowledge of local suppliers and of the general logistics organization. This providing he has not been deeply affected by the shock of the blowout. - He shall be relieved from any other duty if deemed necessary. 	<ul style="list-style-type: none"> - Planning and Supervision of Capping operations. - Submit to the BCTF leader all the plan of actions he has approved. - He is the only person entitled to give orders/instructions to the Capping Consultant - Define materials and equipment - Preparation of the Capping Operations and decision tree. - Liaison with the Blowout Advisor and Capping Consultant to find out the quickest and the safest way to kill the well. - He shall supply the above specialist with all data in relation to the concerned installation. - He shall give assistance to the Capping Team. - He is responsible for carrying out the technical investigation with the local suppliers so as selecting the specific equipment required. He then passes the investigation results to Logistic for actions.
Drilling Engineer	Supply the Blowout Advisor with field data as well as the Capping Consultant.	<ul style="list-style-type: none"> - Preparation of the capping program and in relation with Drilling Superintendent and Capping Consultant. - Liaison with capping specialist and Operations safety representative to Organize efficient well site safety and security coverage.
		<ul style="list-style-type: none"> - Responsible for supplying pertinent well and field data.
Mud Superintendent	Staff with a perfect knowledge of local supplying capacities for swift assistance to the capping team.	<ul style="list-style-type: none"> - Assistance to the capping team to find all required killing equipment such as pumps, killing fluid, piping.

Capping Team Member	Origin	Responsibilities
Capping Consultant	<p>Recommended companies are:</p> <ol style="list-style-type: none"> 1. Wild Well Control Inc. (WWCI) 2. Boots & Coots IWC (B&C/IWC) 3. Alert Disaster Control Singapore 4. Cudd Well Control (CWCI) 	<ul style="list-style-type: none"> - Organization and safety for capping personnel and operation. - They shall advise the BCTF Leader and the Capping Operation Leader and report to them. - They receive orders only from the capping Operation leader. - They may require the assistance of the Drilling Superintendent and Logistic support for the supply of any required item. - They will require data from the Drilling Engineer. - Once their plan of action is completed they must get the approval of the Capping Operation Leader before implementation.
Logistic Support	<p>A minimum of two (2) persons must be assigned to the Capping Team. One will be in charge of the Procurement and the other one of the Transport.</p>	<ul style="list-style-type: none"> - Urgent contact with the local Assistance Organization (if any), in liaison with the safety team, in order to bring the additional facilities to the field, to fight the fire, to provide lifting and power facilities. - Assignment of supply boats in liaison with the Marine Superintendent and of the Helicopters to the exclusive use of the capping operations. <p>Mobilization of emergency accommodation for the various specialized personnel and additional hands required to carry out construction, firefighting, debris cleaning.</p> <p>Coordination of all engineering tasks to be implemented on the blowout site (works for supply, spraying, placing protection shield, illumination for night works...).</p> <p>Organization of an efficient and rapid transportation of all specific equipment (from USA or EU).</p> <ul style="list-style-type: none"> - Quick settlement of all purchasing and rental paperwork, for earliest delivery. - Rapid contact with all possible suppliers. - Massive and rapid purchase of cement and barite that might be required for killing operations.

Relief Well Operations

Relief Well Team Member	Origin	Responsibilities
Relief Well Leader	<ul style="list-style-type: none"> -Should normally be Senior Drilling Engineers -Shall have a good leadership capability and a good knowledge of PTTEP field's specific problems. -He also needs experience in directional drilling in the Gulf of Thailand. 	<ul style="list-style-type: none"> - Planning and supervision of relief well drilling, completion and subsequent kill . - Shall submit to the BCTF Leader all the programs of action for approval, review or comments.
Drilling Engineer	<ul style="list-style-type: none"> - Engineer with a good knowledge of BHA behaviour. - He must be experienced drilling engineer to be able to rapidly starts to organize a possible relief well. - He shall be relieved from any other duties. 	<ul style="list-style-type: none"> - Preparation and day to day follow up of the program with the directional coordinator. - Preparation of the relief well decisions tree. - He is responsible for finding all directional equipment and proximity tools. - He shall provide full assistance to the directional coordinator, as well as all the data required by him. - He is responsible for the relief well casing design and geometry according to the selected kill strategy and program. - Liaise with kill coordinator and reservoir engineer
		<ul style="list-style-type: none"> - Carry out all necessary calculations related to the relief well options. - Work out the necessary pumping pressure and power required to stop the blowout. - To advise the killing coordinator.
Reservoir Engineer	PTTEP or PARTNERS shall be integrated in the BCTF He must be an expert in mono or biphasic flow calculations	<ul style="list-style-type: none"> - To liaise with the blowout advisor to supply him data required for the killing calculations. - To liaise with the killing coordinator and perform the necessary computer runs to assess the BHFP, the required kill pumping rate and the related killing procedure. - Evaluate the possible depletion that may affect the formations drilled by the relief well.
Mud Engineer	If both capping and relief well activities are ran in paralleled the local Mud Engineer will need external support.	
Drilling Superintendent	PTTEP staff or PARTNERS if needed	<ul style="list-style-type: none"> - Follow up of day to day drilling operations. - Shall be involved in the selection of the relief well drilling rigs and shall closely supervise the BOP inspection and refurbishing. - Shall liaise with the Kill coordinator to select the proper kill string.
Directional Coordinator	Contracted. Must be an expert in directional drilling	<ul style="list-style-type: none"> - Lead the relief well location. - Deciding in cooperation with the

Relief Well Team Member	Origin	Responsibilities
	and proximity tools.	<p>Drilling Engineer the directional drilling and survey policy of the relief well.</p> <ul style="list-style-type: none"> - To submit the program to the Relief Well leader for approval. - Fully in charge of field leadership. - Shall be the only person to give orders or instructions to the offshore directional team and to the proximity tool operator.
Kill Coordinator	<p>Contracted</p> <p>Must be a specialist having already managed similar operations and / or having a good knowledge of HP pumps technology.</p> <p>He shall be nominated as soon as the blowout has initiated to immediately start to investigate on pumping equipment needed.</p>	<ul style="list-style-type: none"> - Immediately investigate for pumping equipment available in the South East Asia, Europe and United States. - Calling out for a competent pump expert from Halliburton or Dowell or BJ and put at PTTEP sole disposal. - Design the equipment layout with the pump expert. - Organize the kill program as per the selected killing procedure. - Liaise with Reservoir and Petroleum engineers and workout the pumping program in order to avoid any formation breakdown. <p>Investigate according to the situation the need of a second kill line system is necessary and settle the matter with the suppliers, in liaison with the Drilling Superintendent regarding all matters in relation with BOP risers modifications.</p> <ul style="list-style-type: none"> - Liaise with the Drilling Superintendent to design the kill string, to check the rig deck space, pit capacity, BOP design, riser modifications, quality control..... - Request Mud Engineer to build the kill mud for the relief well. Assign specific transportation means to the relief well rig.
Pump Expert	<p>Contracted from one company like Halliburton, Dowell or BJ.</p> <p>He must be competent in massive pumping operations and if possible some experience in this kind of operation.</p>	<ul style="list-style-type: none"> - Organize the localization and the availability of all necessary pumping units in South East Asia, United States or Europe. - Perform the pre-assembly, test and modifications if needed onshore. - Organize the future offshore pattern. - Planning for offshore transportation, spare parts, offshore hook-up, water and mud supply, monitoring, communications, etc. - Selection of the proper surface piping and manifolding in order to minimize the pressure drops.
Drilling Supervisor	<p>As a 24 hours continuous supervision is mandatory two (2) supervisors will be needed.</p> <p>They must have a consistent experience in regards with the type of rig selected for the relief well operation.</p>	<ul style="list-style-type: none"> - Supervision of the relief well operations and drilling on site. - Permanent communication with the Drilling Superintendent. - Give to the onshore team all the information needed to make the best decision.

Relief Well Team Member	Origin	Responsibilities
Rig Engineer	Only if deemed necessary by the BCTF leader. Must have experience in directional and well engineering.	- Adaptation and follow up of the relief well engineering on a day-to-day basis.
Mud Supervisor	One must be assigned in each supervision team.	- In charge on site of the follow up of the mud program.
Logistic Support	A minimum of two (2) persons must be assigned to the Relief Well Team. One will be in charge of the procurement. One will be in charge of the Transports	Release the casing required. Arrange for urgent delivery if not available. - Investigate with other operators stocks. - Arrange reception/storage for extra equipment in pre-designated area. - Assistance to the transfer of the relief well rig to the required location.

9.4 BLOW OUT RESPONSE PLAN IN 1ST 24 HOURS

PTTEP Emergency Response Team (ERT) will be activated after received notice of emergency from offshore. The initiate action need to be done in first 24 hrs as follow.

- Initial evaluation
- Make personnel assignments
- Develop Initial Action Plan and Approve
- Issue Initial Action Plan detail to field
- Mobilize outside experts
- Make notices to Government and Partners
- Mobilize fifi boats and oil booms
- Activate BCTF

PTTEP Emergency Response Team (ERT) Mobilization

The procedure shall be as per PTTEP EMP Manual and the alert diagram shown in the Notifications section 2.3 of this plan.

Action Required	Action By
Notification of the Blowout to TSD, OTF, or Duty Officer and Field Manager	Drilling Supervisor or Duty Drilling Superintendent
Notification of the blowout to EVP, VP or acting VP. and TSD.	TSD, OTF or Drilling Superintendent or Duty Officer
Assembly of the ERG in PTTEP Emergency Response Room in ENCO office building A 29th floor, room 2948	TSD (Authorization by EVP, actual callouts by Duty Officer/telephone operator)

9.4.1 First Priorities assigned to the ERT (first hours after the blowout)

Once all personnel has been safely evacuated, the main objective is to initiate simultaneously the Capping operation and the Relief Well preparation, whilst safeguarding the installation. (refer to PTTEP Emergency Management Plan)

Always remember that, it is as important thinking about the vital need to slow down the fire destruction effect as initiating capping and relief well activities. The Logistics efforts will thus be of prime importance to ensure that all available firefighting means are on the site before the arrival of the capping team, so as:

- to avoid a total havoc and destruction from the fire.
- to facilitate the capping team job.
- However, obtain first of all a correct assessment of the situation:
- discuss with the PIC at the rig or location if still feasible
- obtain reports from witnesses still on the scene (supply boats, helicopters).
- organize (if needed/if possible) helicopter flights to visualize the disaster.

The objectives are:

- To give assistance to the casualties.
- To assess the **magnitude** and the type of problem.
- To determine the type of flow and source of flow.
- To identify the number of blowing/burning well.
- To evaluate the need for firefighting.
- To assess the extent of the structural damages.
- To find out whether the main power of the platform has been totally/partially lost.

Once this has been done it is important to avoid dissipation of energies and repetition of major phone calls, to define each person objectives, and to ensure the effective mobilization of the BCTF

At that time give the first major phone calls.

Action Required	Action By
Contact government and local authorities, and request support (Hospital, Police, Thai Navy, etc.)	TSD
Organization of the BCTF (see table 1 and 2 in section 2)	TSD/O
Contact with Partners to notify the blowout. Request Partners Rep. to come to Bangkok PTTEP Office. Request extra personnel assistance to: Take over routine activities (if any). Take part in the BCTF organization. (if required)	TSD
Notify the blowout to the rig owner and all subcontractors.	TSD/O
Contact the Blowout Advisor	TSD/O
Contact Insurance Co. and request the Insurance surveyor to come to Bangkok.	FAC
Contact Capping consultant.	TSD/O
Contact with "Operator Assistance club", if any, to call for MSV, crane barge, cranes, firefighting support.....	OLG
Assignment of workboats and helicopter exclusively to the blowout.	OLG

9.4.2 Second Priorities (First 24 Hours after the blowout)

The objectives are

- To finalize the BCTF organization.
- To start investigating about the major required equipment (Capping, Relief Wells).
- To initiate massive purchasing (barite, cement).
- To gather the fundamental data required by the "Crisis Cell" and the Consultants.

Action Required	Action By
Select all required Partners assistance team.	EDL/O (BCTF leader)
Instruct Drilling Engineer to start gathering data on the blowing well.	Capping Operation Leader
Contact Rental Suppliers to specify equipment required by Capping Consultant.	Drilling Superintendent (Capping Ops.)
Notify DOWELL/HALLIBURTON /BJ to initiate search for pumps required by Capping Consultant.	Drilling Superintendent (Capping Ops.)
Organize heavy logistics to bring specific equipment (Capping) from Singapore, USA or Europe if needed	Logistic Coordinator (Capping)
Arrange for urgent transfer of extra firefighting support units to the site.	Logistic Coordinator (Capping)
Investigation about available drilling rigs for the Relief Wells.	Relief Well Leader
Notify to Directional Drilling Co.to put tools on standby and to mobilize experienced directional team.	Drilling Engineer (Relief Well)
Notify to Proximity Tools Co. to investigate on tools and delivery conditions.	Drilling Engineer (Relief Well)
Mobilize the means to fight or contain pollution if needed.	SSHE Manager

9.4.3 Convening the “Crisis Advisory” (within 48 hours after the blowout)

Once the “Crisis Advisory” members have been gathered in Bangkok (Special conference room, different from the ERT) all gathered data are supplied so as to assist them in decisions making.

Information about the “Crisis Advisory” suggestion / recommendations are given to the TSD by the BCTF leader.

The objectives of that phase is to define the delicate first steps of action. The experience / judgment of the PTTEP Manager and Partners Representative and blowout Advisor will be of particular importance, to assess the feasibility of a direct cap and kill which would not worsen the situation and/or put the whole structure in jeopardy

9.5 BLOW OUT RESPONSE PLAN IN CYCLE 2-5 DAYS

Once the BCTF is properly organized, and once the major options have been taken by the “Crisis Cell”, the next step involves the practical implementation of the said options by the two BCTF teams.

This is a non-exhaustive list of the main actions which shall be taken so as to start capping and relief well activities under shortest term:

Relief Well Team

Action Required	Action By
Convening a Kill Strategy meeting to: <ul style="list-style-type: none"> Set up the type of killing procedure Decide on the number of killing wells. Define exact calculations and reservoir simulation requirements. Assess the possible type of pumping support. 	Relief Well Leader Kill Coordinator Reservoir Engineer Petroleum Engineer
Convening a Directional Strategy meeting to: <ul style="list-style-type: none"> Decide on general relief well(s) profile / program. Analyse all potential problems (Surface formation pressure charging.) Decide the surface location of the relief wells. Select the directional equipment. 	Relief Well Leader Drilling Engineer (Relief Well Team) Directional Coordinator Reservoir Engineer Drilling Superintendent (Relief Well Team)
Notification to SCHLUMBERGER / HALLIBURTON / BJ to initiate search for pumping support (skid unit or frac vessel) needed for the killing through the relief well.	Kill Coordinator
Inspection of the drilling rig(s) (if needed) to be used for the relief well.	Drilling Superintendent (Relief well team)
Preparation of the relief well programs and decision trees.	Directional Coordinator Drilling Engineer (Relief Well Team)
Release of casing for relief wells. Prepare to receive / store extra equipment / material in pre-designated area.	Logistic Support (Relief Well Team)
Transfer of selected rig to the relief well location. Transportation of all equipment to rig.	Logistic Support (Relief Well Team) Marine Superintendent
Installation of communication Network on the rig (if needed)	HIT
Analysis / Finalisation of Relief Well program and decision trees.	BCTF Leader Relief Well Leader

Capping Team

Action Requested	Action By
Convening a Capping Strategy Meeting to: <ul style="list-style-type: none"> Set up the field action/coordination Set up the exact requirements for equipment. Set up the logistic support / assistance. 	Capping Operation Leader Capping Consultant Drilling Superintendent (Capping Team) Drilling Engineer (Capping Team) Logistic Coordinator (Capping Team)
Preparation of Capping program and decision tree.	Drilling Engineer (Capping Team) Drilling Superintendent (Capping Team) Capping Consultant
Analysis / finalisation of the Capping program and decision tree.	BCTF Leader Capping Operation Leader
Transfer of specific equipment required for the capping to the site. Follow up of firefighting conditions, supply of back-up means if needed.	Logistic Coordinator (Capping Team)

Remark: Blowout Capping, Relief Well Drilling and Kill Strategy meetings shall be run simultaneously:

Blowout Capping is to be treated as urgent and with priority.

Kill Strategy will have a tremendous impact on relief well design (diameters) and profile (depth of kill, proximity required), on rig equipment, pumping equipment, kill fluid types, pump rates and pressures, etc.

Relief Well Drilling requires an extensive equipment mobilisation.

Before starting the operations do remember an important factor which will be very important for proper implementation of decisions and for logging of events:

Set all leaders' watches to ZERO, make sure they all show the same time.

9.6 ROUTINE OPERATIONS

According to the PTTEP philosophy three different situations have to be taken into account, which are:

- A blowout on the Exploration/Delineation rig operation.
- A blowout on the Development rig operation.
- A blowout on the Production Facility (production operations, wireline, coiled tubing, etc.

9.7 GEOLOGICAL ASSISTANCE

A geologist will be entirely dedicated to the relief well operations.

The mud logging company selection for the relief well shall be left in the hands of the Relief Well Operation leader.

9.8 SAFETY MEASUREMENTS AND ASSISTANCE

The ERT should be aware, following a blowout, of the potential of further incidents resulting from a lack of preventive measures.

Although many aspects of these safety measures will be met and attended to in the normal course of communication with various authorities and specialist groups, care should be taken in the following area:

- The setup of safety zone around the site of the blowout. All shipping in the vicinity, and for the duration of the emergency, should be made aware of the hazard.
- The Thai Navy should be continually kept informed on the area affected by the blowout.
- Adjacent facilities and any marine activities should be notified of the situation as soon as possible by whatever means necessary.
- All assessments of the situation should be notified to any craft proceeding toward the area to help in dealing with the emergency. This should enable the timely provision of the necessary safety facilities to protect personnel and equipment on board.

ALL THESE ACTIVITIES HAVE TO BE PERFORMED IN CO-ORDINATION WITH THE NAVY VIA THE PTTEP HSE MANAGER.

It is suggested to request the assistance of CSH and/or partners and ask for the most experienced and competent safety personnel especially in the case of pollution.

It is suggested also to call for people field experienced with blowout events.

The safety team shall focus on:

- Mobilizing rescue facilities and protective clothing.
- Providing full medical and evacuation support close to the blowout site.
- Evaluating the fire-fighting needs. Remember that the well capping success highly depends on the quick response to the fire destructive effect (*)
- Carrying out gas monitoring and erecting warning signs.
- Evaluating the needs to fight against the pollution.
- Identifying hazardous areas and finding out whether it is necessary (in cooperation with the blowout advisor) to ignite the blowout to secure the safety of the people.
- (*)Note that the "Blowout Concept" shall be taken into account when designing the fire-fighting equipment of offshore development drilling platforms.
- The main objective is to be able to cool the structures and avoid its collapse.
- Advise the capping consultant on safety matters in order to have a safe capping operation.
- Call for external fire-fighting means and to have these supports on the site in the shortest time.

10.0 APPENDICES

10.1 LOGISTICAL CONSIDERATIONS FOR OFFSHORE AND MAJOR RESPONSE

IMPORTANT: Prior knowledge of what will be required and how it can be obtained will be extremely important. This is precisely what this section will outline and discuss. One of the very first assignments of the Incident Manager should be to designate the Logistics Coordinator to locate and define the availability of equipment and services required to respond to a major blowout.

In the event of a major blowout, efficient mobilization of the necessary equipment will depend on knowledge of what equipment is needed. This section provides guidance on such logistical considerations.

A listing of the equipment typically requires for a large surface blowout is outlined below. In Thailand, much of this type of equipment is available and can be procured in country. If this equipment is unavailable, specialized firefighting equipment has to mobilize from Houston and Singapore.

10.1.1 Logistics

PTTEP's logistic base, Petroleum Development Support Base (PSB), is located in the Singhanakorn District at 07° 14' N 100° 34" E close to the entrance of Songkhla Lake. The Base is about 50 km from Hat Yai Airport and 30 km from Hat Yai railway station. Access to the Base by road is either via Highway 407 from Hat Yai or by coastal Highway 408 from Nakorn Srithammarat. The base is about 900 km North of Singapore by road.

PSB will be used as the logistic base to support the three fields covered by this plan, namely, Bongkot, Arthit and Nang Nuan, which are at a distance of about 110, 132 and 195 nautical miles from the base, respectively. PSB is the subsidiary of PTTEP International. It is the only dedicated supply base supporting oil and gas industry in the Gulf of Thailand. It operates year round, 24 hours a day. Base facilities include a six-berth Jetty, warehouses, open storage yards, bulk storage tanks and silos, cold storage, workshops, and a marshalling yard. The facilities are fully protected by security services. All marine activities are controlled from the Operations Centre in the Base Administrative Building. PSB is located close to Songkhla Deep Sea Port, and within easy reach of PSB Heliport, Songkhla Town and Hat Yai Airport.



Excluding the organization of the blowout intervention team, the most complicated and typically overlooked components of implementing an emergency project are the logistics of required services and equipment. Many of these services are very specialized and may not be available in the immediate region or area. Also, knowledge of many of these services and the companies which provide such services may be unknown to the typical oil company engineer who has minimal experience with an intervention project.

An expensive and time consuming learning curve, with sometimes disastrous results, has been evidenced in many projects which utilized standard services beyond their capabilities and overlooked details which became insurmountable. There are methods to reduce the associated problems with good logistics practices for any project. The primary one is planning for what will be required and how it can be obtained.

10.1.2 Drilling Rigs

PTTEP is currently operating jack-up drilling rigs and tender assist barge for support exploration and development campaign.

10.1.3 Location and Distances

Distances and ETA

Point of Reference		Approximate Distance	ETA	By Mean		
From	To			Trailer Truck	Air	Sea
Singapore	Logistic Base in Songkhla	900 km	10 hrs	X		
		900 km	2 hrs		X	
Songkhla	Nang Nuan	195 nm	20 hrs			X
		361 km	1.5 hrs		X	
Songkhla	Bongkot	110 nm	12 hrs			X
		204 km	50 min		X	
Songkhla	Arthit	132 nm	14 hrs			X
		244 km	1 hr		X	

Petroleum Development Support Base (PSB) Coordinates and Addresses

07° 14' N 100° 34" E

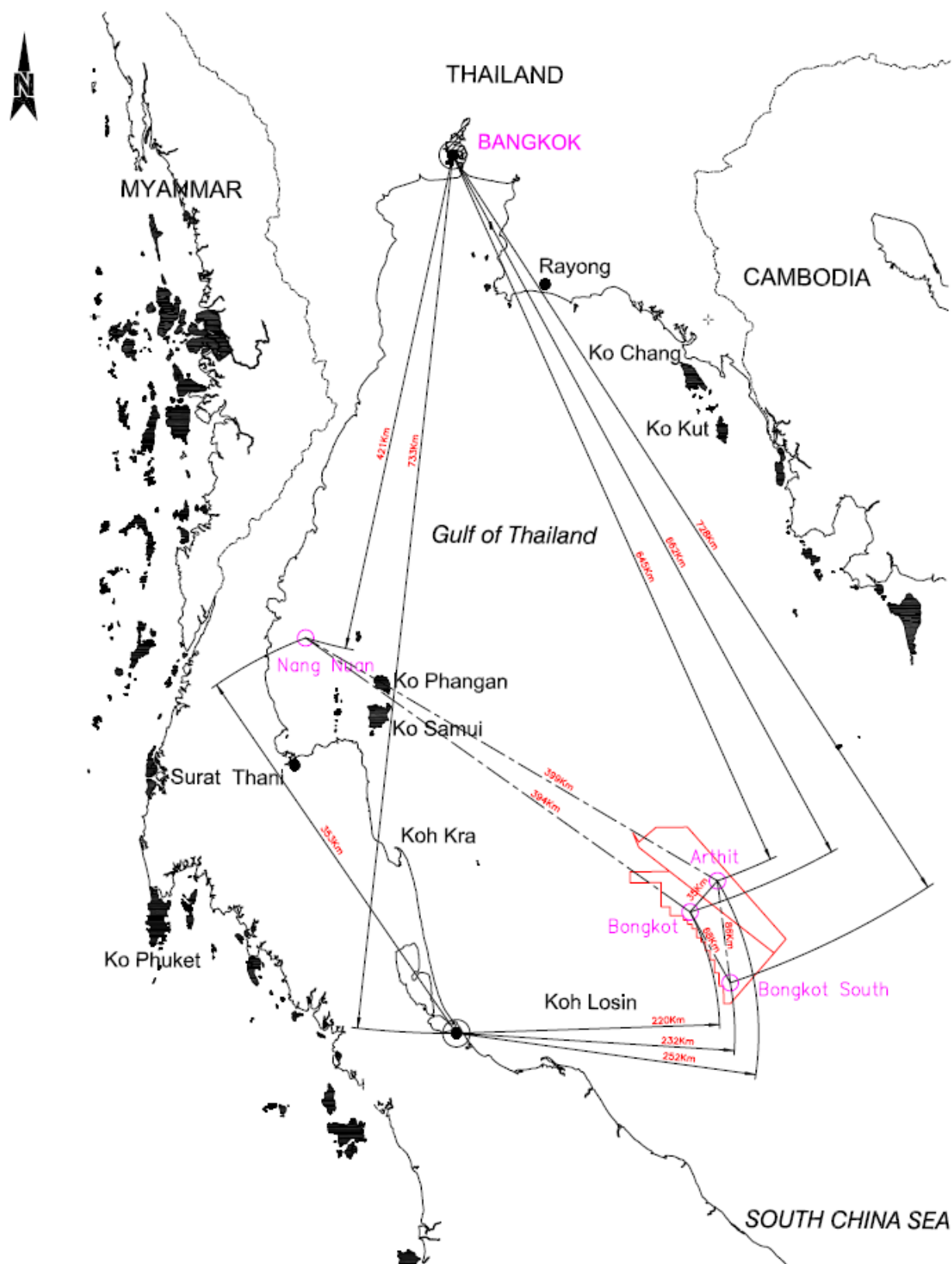
PTTEP Offices in Bangkok

Energy Complex Building A Floors 6, 19-36

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P: +66(0) 2537-4000

F: +66 (0) 2537-4444



10.1.4 Met-Ocean Information (Gulf of Thailand)

The Gulf of Thailand is bordered by [Cambodia](#), [Thailand](#) and [Vietnam](#). The northern tip of the gulf is the [Bay of Bangkok](#) at the mouth of the [Chao Phraya River](#). The gulf covers roughly 320,000 [km²](#). The boundary of the gulf is defined by the line from [Cape Bai Bung](#) in southern Vietnam (just south of the mouth of the [Mekong](#) river) to the city [Kota Baru](#) on the Malayan coast. At the height of the last [ice age](#) the Gulf of Thailand did not exist, due to the lower sea level, the location being part of the Chao Phraya river valley.


The Gulf of Thailand is relatively shallow: its mean depth is 45 [m](#), and the maximum depth only 80 m. This makes water exchange slow, and the strong water inflow from the rivers make the Gulf low in [salinity](#) (3.05-3.25%) and rich in [sediments](#). Only at the greater depths does water with a higher salinity (3.4%) flow into the gulf from the [South China sea](#) and fills the central depression below a depth of 50 m. The main rivers which empty into the gulf are the Chao Phraya (including its distributary [Tha Chin River](#)), [Mae Klong](#) and [Bang Pakong](#) Rivers at the [Bay of Bangkok](#), and to a lesser degree the [Tapi River](#) into [Bandon Bay](#) in the southwest of the gulf.

< <http://www.answers.com/topic/gulf-of-thailand#ixzz1I4vU8VbT> >

10.1.5 Petroleum Development Support Base (PSB) Jetty Facilities.

10.1.6 Transport

In the event additional heavy equipment should need to be transported from Singapore or Houston, it would arrive at Hat Yai International Airport.

Hat Yai International Airport			
<div><div></div><div><u>IATA</u>: HDY – <u>ICAO</u>: VTSS</div></div>			
Summary			
Airport type		Public	
Operator		Airports of Thailand	
Location		Hat Yai , Thailand	
Elevation <u>AMSL</u>		90 ft / 27 m	
<u>Coordinates</u>		<div><div></div><div>06°55′59″N 100°23′34″E6.93306°N 100.39278°E</div></div>	
<u>Runways</u>			
<u>Direction</u>	Length		Surface
	ft	m	
08/26	10,007	3,050	Asphalt

10.1.7 Heavy Airfreight

The Russian 124 Antonov aircraft brokered by Heavylift Air Cargo Ltd., Standsfield, U.K. can be made available (24 hour operations center phone number is 44-279-680611. This aircraft is capable of hauling 120 metric tons of oddly proportioned equipment and capable of hauling a



Heavylift Aircraft would land at the Hat Yai International Airport where the runway length can accommodate the Antonov 124 or 747-400.

[illegible]

10.1.9 Incident Response Challenges at PTTEP offshore Locations

Personnel, equipment, and supplies during an incident will be flown to the installations or the drilling rigs (Level III) by helicopter or supply vessel (approximately 1 to 1.5 hours by helicopter and 12 to 20 hours by supply vessel). The main obstacles are:

- Distance from the Onshore Base.
- Transportation of Equipment, Supplies and Personnel
 - Any additional equipment, supplies and personnel will have to be mobilized via helicopter or supply boat. All heavy equipment and machinery will have to be transported by supply boat only.
- The limitations in working area and space typical of an offshore drilling facility.
 - Limits the ability to place additional well control auxiliary equipment.
- Any major incident will require evacuating all non-essential personnel from the drilling unit.
- Offshore operations represent a challenge.
- High seas that impede mobilization of equipment and personnel.

10.1.10 Role of a Rig Contractor

The key to successful blowout control is fast and efficient mobilization of the required support. The following list is not complete but can be used as a reference as to what may be required. The greatest key team member if a blowout is experienced will be the rig contractor, especially if they are experienced in how to acquire local available services, equipment and materials. The rig crew may be needed to assist the well control specialists. PTTEP should hold a pre-planning meeting with the rig contractor and discuss these and any additional points:

- Third party billing and purchase order system
- Cash flow assistance (must maintain good credit with local vendors)
- Increased rig crew pay for hazard duty (triple time is not uncommon)
- Added staff from rig contractor to handle logistical duties
- Spare equipment sources (ex: BOPs & choke manifolds)
- Welding/fabrication sources
- Oilfield supply sources
- Implementation of the fire water system

10.1.11 Minimum Recommended Firefighting Equipment

10.1.12 Specialized Firefighting Equipment

Quantity	Mobilized	Description
2		Fire pumps, minimum 4000 gpm @150 psi
1		Pipe rack, complete with suction & discharge hoses, water monitors, pipe nipples, fittings, butterfly valves, flanges, hammer unions, aluminium pipe, high temperature cloth, etc. necessary in rigging up fire pumps (see pipe rack inventory)
1		Job Box, complete with hand tools, hammer wrenches, brass hammers, air impact wrenches w/sockets, pipe wrenches, air grinders etc. (see job box inventory)
30		4" x 20" aluminum pipe w/indusco fittings
4		8" x 20' oil, suction and discharge hose complete with figure 100 hammer union
12		4" x 10' discharge hose complete w/ fig. 100 hammer Union
6		4" x 10' discharge hose complete w/ fig. 100 hammer union/male aluminium adapter
6		4" x 10' discharge hose complete w/ fig. 100 hammer union/female aluminium adapter
2		4" Stang monitors complete w/ nozzle & base
1		2" – 5" Porta-Lathe cutter
1		3" – 6" Porta-Lathe cutter
1		6" – 9" Porta-Lathe cutter
1		9" – 14" Porta-Lathe cutter
1		14" – 16" Porta-Lathe cutter
1		18" – 20" Porta-Lathe cutter
1 Lot		Miscellaneous spare parts for Porta-Lathe cutter
20		Double edge cutter blades for Porta-Lathe cutter
1		Halliburton Abrasive Jet Cutter
1		Spare parts for fire pumps
1		Junk shot Manifold complete w/rope, rubber, steel balls, golf balls and other plugging material

10.1.13 Rental Equipment

Quantity	Mobilized	Description
1		185 cfm air compressor
4		Light plants, trailer mounted
1		Generator
2		Pressure Washers

10.1.14 Metal for Fabricating Support Equipment

Quantity	Mobilized	Description
250 Sheets		3' x 8' sheets corrugated tin
1000 ft.		Large diameter pipe for fire water supply line (12" – 16")
1 sheet		2" steel plate
2 sheets		1" steel plate
2 sheets		½" – 5/8" steel plate
1500 ft.		2" x 2" x ¼" angle iron (heat shields for bulldozers)
50 sheets		3/16" or ¼" diamond plate, expanded metal or floor grating (flooring for monitor sheds, cutting sheds, etc.)
2000 ft.		2 3/8" or 2 7/8 " junk tubing (structural for building monitor sheds, sheds and heat shield)
1 Lot		Casing for diverter lines

10.1.15 General Oilfield Supplies

Quantity	Mobilized	Description
6		8" Figure 100 hammer unions
6		6" figure 100 hammer unions
12		4" figure 100 hammer unions
6		8" x 12" pipe nipples, threaded both ends
12		6" x 12" pipe nipples, threaded both ends
12		4" x 12" pipe nipples, threaded both ends
6		4" wafer type butterfly valves
12		4" 150# R.F. threaded flange
50		5/8" x 6 1/4 " studs w/nuts both ends
10 rolls		Tie wire
20		3/8" x 15' high test chain w/grab hooks
40		2" shackles, pinned
40		1 ¾" shackles, pinned
40		1 ½" shackles, pinned
40		1 ¼" shackles, pinned
40		1" shackles, pinned
40		¾" shackles, pinned
1-roll		½" manila rope
1 roll		¾" manila rope
4		200 psi liquid filled gauges
4		600 psi liquid filled gauges
4		1000 psi liquid filled gauges
4		3000 psi liquid filled gauges
4		5000 psi liquid filled gauges
4		10000 psi liquid filled gauges
2 Boxes		Shop Rags
2		Snatch blocks for 1 1/8" cable, shackled not hooked
		Structural lumber (2 x 4's) for heat shields

1		Awning
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10.1.16 Specialized Oilfield Supplies

Quantity	Mobilized	Description
10 min.		Tanks for fire water or mud supply
2		Large volume diesel driven water transfer pumps (3000 gpm min.)
2		Mud charging pumps (to feed pumping equipment and tanks)
1		Mud system – complete with mixing and circulating capabilities
1000 ft.		High pressure tubing, for pumping or cutting operation (to maintain good distance between well and pumping equipment) size to be determined per requirement
1		Coil tubing unit
1		Snubbing Unit

10.1.17 Explosives and Associated Supplies

Quantity	Mobilized	Description
1000 lbs.		Explosives, 90 – 100%, general oilfield type
		Dry chemical
		Blasting caps for explosives
4		55 gallon drums
2000 ft.		auge wire, 2 wire minimum

10.1.18 Cables, Slings and Clamps

Quantity	Mobilized	Description
2000 ft.		1 1/8" 6 x 36 soft lay cable (for rig removal)
1000 ft.		1/4" 6 x 36 soft lay (slings for debris removal)
1000 ft.		5/8" 6 x 36 soft lay cable (slings for debris removal)
100		11/8" cable clamps
100		3/4" cable clamps
100		5/8" cable clamps
10		1 1/2" x 10' wire rope slings 6 x 36 soft lay cable
20		1 1/4" x 10' wire rope slings 6 x 36 soft lay cable
20		1 1/4" x 20' wire rope slings 6 x 36 soft lay cable
20		1" x 10' wire rope slings, 6 x 36 soft lay cable
20		1" x 20' wire rope slings, 6 x 36 soft lay cable
40		3/4 " x 10' wire rope slings, 6 x 36 soft lay cable
40		3/4 " x 20' wire rope slings, 6 x 36 soft lay cable
40		5/8" x 10' wire rope slings, 6 x 36 soft lay cable
40		5/8" x 20' wire rope slings, 6 x 36 soft lay cable

10.1.19 Welders and Associated Equipment

Quantity	Mobilized	Description
6		Structural welders with helper and equipment
1		Certified Welder with Helper and equipment
4		Cutting torch complete with large supply of oxygen, acetylene and accessories, 250 ft. of hose per torch, strikers, tip cleaners and spare tips
2		Long reach cutting torch, complete with large supply of oxygen, acetylene and accessories, 250 ft. of hose per torch, strikers, tip

		cleaners and spare tips
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10.1.20 Personal Protective Equipment (PPE), Personnel and Equipment

Quantity	Mobilized	Description
1		Decontamination area for personnel with change room
1		Decontamination area for equipment
2		Wind socks
		Flagging tape
6 min.		Two way radios with headsets
1 lot		Work gloves, ear plugs for work force
1		Weather forecast updated regularly
		Living accommodations for crew
		Meals for all work force
1 lot		H ₂ S equipment (if necessary)
1 lot		Drinking water with water cooler and cups
1 lot		Rain suits
1 lot		Rubber boots, work gloves and ear plugs for work force

10.1.21 Wellhead and Capping Equipment

Quantity	Mobilized	Description
1		Replacement wellhead for blowout well
1		Capping stack
1		Choke manifold
1		Choke house
1 lot		Spacer spools
1 lot		Diverter spools
1 lot		Spare flanges for diverter lines
1 lot		Spare parts for capping equipment (ring gaskets, studs, etc.
1		Extension tube for capping BOPS
1		Wellcat tool box
1		Mud/Gas Separator
1		Bowl/Slips
1 lot		Chicksan Iron Basket (loops, swings, straights, tees)
		Plug valves
		TIW valve w/handle
1		Drillpipe tree

10.2 LOGISTICAL CONSIDERATIONS FOR ONSHORE AND MAJOR RESPONSE - IMPORTANT

Prior knowledge of what will be required and how it can be obtained will be extremely important. This precisely what this Document will outline and discuss. One of the very first assignments of the incident Manager should be to designate the Logistics Coordinator to locate and define the availability of equipment and services required to respond to a major blowout.

In the event of a major blowout, efficient mobilization of the necessary equipment will depend on knowledge of what equipment is needed. This section provides guidance on such logistical considerations.

A listing of the equipment Boots & Coots typically requires for a large surface blowout is outlined below. In Thailand, much of this type of equipment is available and possibly be procured in country. If this equipment is unavailable, Boots and Coots has specialized firefighting equipment in Singapore and Houston and this equipment could be mobilized from there.

10.2.1 Logistics

The logistic base supporting PTTEP Thailand's onshore operations (S-1 and Ratana Fields) is located in the S-1 block about 400 km North of Bangkok. The Ratana field is about 400 km east of the S-1 logistic base, with a trucking time of about 8 hrs between the two locations.


In an emergency large cargo would move from Singapore or Houston to either Phitsanulok Airport (80 km from Ratana). An alternative would be trucking the equipment if coming from Singapore, which would require about two days of travel time.


10.2.2 Regional Perspective



10.2.3 Transport

In the event additional heavy equipment should need to be transported from Singapore or Houston, it would arrive at Phitsanulok Airport (80 km from S-1) or Khon Kaen Airport (80 km from Ratana).

Phitsanulok Airport			
IATA: PHS – ICAO: VTPP			
Summary			
Airport type	Public		
Operator	Government		
Serves	Phitsanulok, Thailand		
Elevation AMSL	154 ft / 47 m		
Coordinates	Coordinates: 		
	16°46′23″N		
	100°16′56″E16.77306°N		
	100.28222°E		
Runways			
Direction	Length		Surface
	m	ft	
14/32	3,000	9,843	Asphalt
Source: DAFIF ^{[1][2]}			

Khon Kaen Airport			
<u>IATA</u>: KKC – <u>ICAO</u>: VTUK			
Summary			
Airport type	Military/Public		
Operator	<u>Military</u>		
Location	Khon Kaen		
Elevation <u>AMSL</u>	670 ft / 204 m		
<u>Coordinates</u>	<u>Coordinates:</u> 		
	<u>16°27′59.86″N</u>		
	<u>102°47′01.18″E</u> <u>16.4666278°N</u>		
	<u>102.7836611°E</u>		
<u>Runways</u>			
<u>Direction</u>	Length		Surface
	ft	m	
03/21	10,007	3,050	<u>Asphalt</u>

10.2.4 Heavy Airfreight

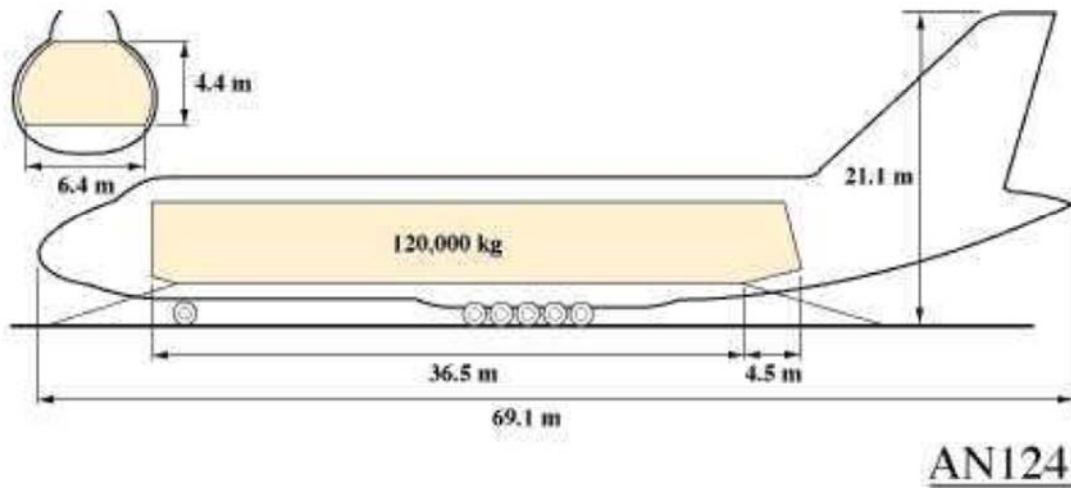
The Russian 124 Antonov aircraft brokered by Heavylift Air Cargo Ltd., Standsfield, U.K. can be made available (24 hour operations centre phone number is 44=279-680611. This aircraft is capable of hauling 120 metric tons of oddly proportioned equipment and capable of hauling a complete set of firefighting equipment and associated equipment for a major fire in a single load and unloading itself. No other commercially available aircraft has this capability.

Nose-load 747 cargo aircraft can also be used to haul all firefighting equipment. The large pipe rack unit and the 20' containers are the most difficult to load in a 747 cargo aircraft. Special cargo handling equipment is required to unload this type of aircraft. Any emergency air cargo charter flight will have to work with Kurdish transport agencies.

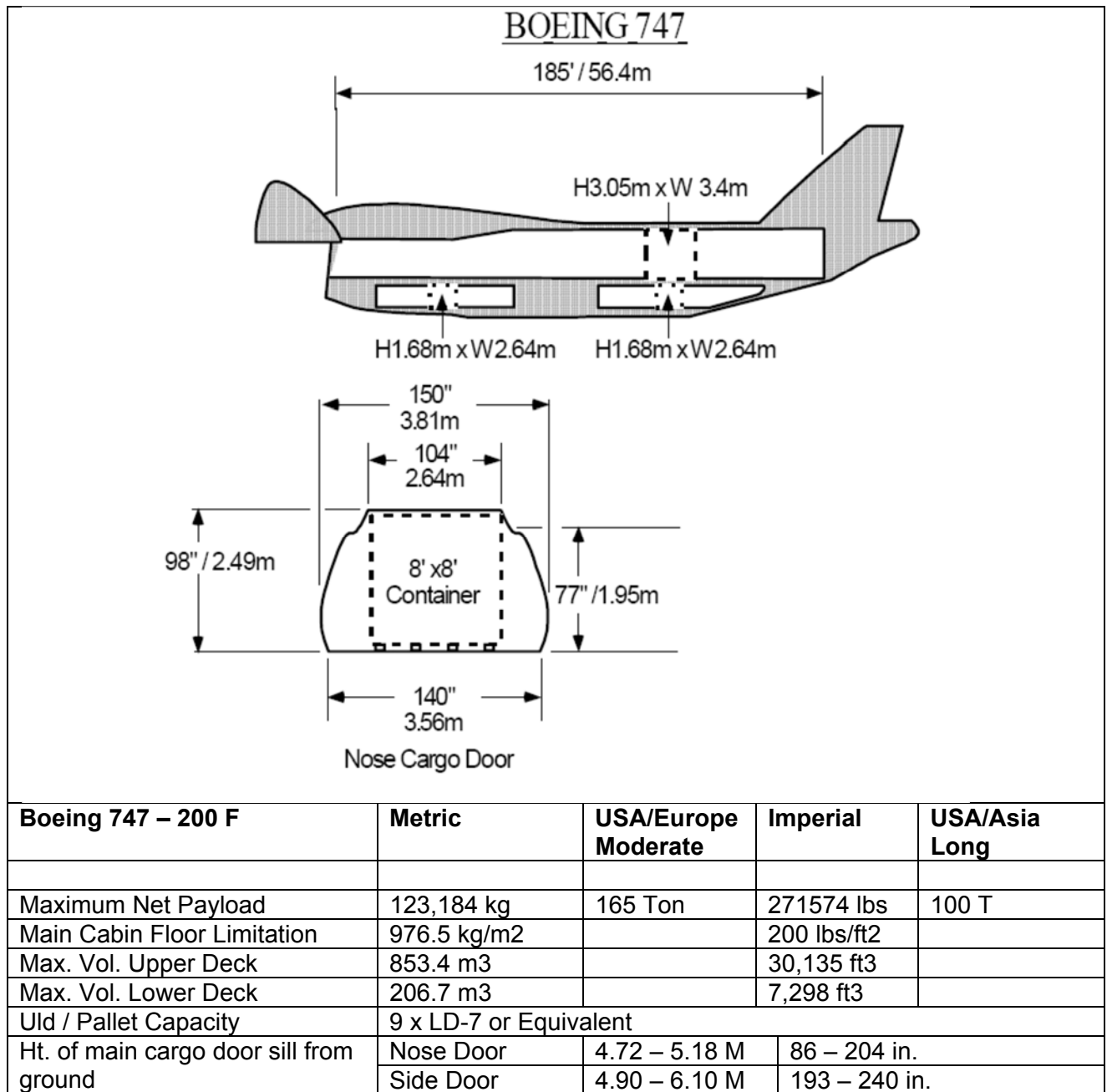
Heavylift Aircraft would most likely land in Khon Kaen or Phitsanulok where runway lengths can accommodate the Antonov 124 or 747-400.


List below are some data on air craft commonly for hire for air cargo.

Aircraft	Payload	Cargo Cabin		
		Length	Height	Width
Antonov 124	120,000 Kgs	36.5 metres	4.4 metres	6.4 metres
Antonov 22	55,000 Kgs	26 metres	4.4 metres	
Antonov 12	15,000 Kgs	23.5 metres	2.4 metres	
Llyushin 76	48,000 Kgs	20 metres	3.4 metres	
Belfast	25,000 Kgs	19.76 metres	3.65 metres	
Begula	74,000 Kgs	37.7 metres	7.10 metres	
Airbua A300 B4	45,000 Kgs	20 x P1 pallets, 20 LD3 containers		
Hercules L100-30	23,136 Kgs	17.07 metres.	2.74 metres	3.12 metres
S-64 E Helicopter	9,071 Kgs	Limited only by payload		
S-64 F Helicopter	11,339 Kgs	Limited only by payload		



Antonov AN-124	Metric	USA/Europe Moderate	Imperial	USA/Asia Long
Maximum Net Payload	150,000 kg	165 Ton	330,693 lbs	100 T
Main Cabin Floor Limitation	10,000 kg/m ²		2048 lbs/ft ²	
Max. Vol. Upper Deck	750 m ³		26,486 ft ³	
Uld / Pallet Capacity	10 x 6 m - 150 Containers			
Ht. of main cargo door sill from ground	218 – 300 cm			86 – 118 in.



				
C-130J-30	Metric	USA/Europe Moderate	Imperial	USA/Asia Long
Maximum Net Payload	19,090 kg	20 Ton	42000 lbs	20 T
Main Cabin Floor Limitation	976.5 kg/m ²		200 lbs/ft ²	
Max. Vol. Upper Deck	105.24 m ³		570 ft ³	
Uld / Pallet Capacity	8 pallets or 97 litters or 24 CDS bundles			
Ht. of main cargo door sill from ground	Rear Door	3.12 M	123 in.	

10.2.5 PTTEP Thailand Regional Perspective

Excluding the organization of the blowout intervention team, the most complicated and typically overlooked components of implementing an emergency project are the logistics of required services and equipment. Many of these services are very specialized and may not be available in the immediate region or area. Also, knowledge of many of these services and the companies which provide such services may be unknown to the typical oil company engineer who has minimal experience with an intervention project.

10.2.6 Incident Response Challenges at PTTEP Onshore Locations

- Remote field location
- Supply of water at high rates at the remote location
- Potential H₂S presence
- Limitedness and/or difficulty of access to the location during the rainy season
- Difficulty of drenching reserve pits at the Ratana location due to the hard nature of the surface.

10.2.7 Establishing a Water Supply

Probably the most important step when controlling a Level III incident is establishing a water supply that will be plentiful and consistent. The plan will be to set up two (2) 4000 or 6000 gpm pumps to supply water. Also, it will be necessary to use a 14-20 inch pipeline from the fire pumps to the fire main manifold which will be placed on the upwind edge of the location. This would enable us to use the water supplied at 153 psi discharge to reach the fire main and the monitor sheds with proper pressure.



10.2.8 Water Supply Storage



10.2.9 Water Supply Calculations

A blowout on fire requires a tremendous volume of water. For example, the following calculations show how fast a 1,000,000 (24,000 bbl) pit would be emptied using various capacity fire pumps.

$1,000,000 \text{ gallons} / (6,000 \text{ GPM} + 6,000 \text{ GPM}) = 83 \text{ minutes}$

$1,000,000 \text{ gallons} / (6,000 \text{ GPM} + 4,000 \text{ GPM}) = 100 \text{ minutes}$

$1,000,000 \text{ gallons} / (4,000 \text{ GPM} + 4,000 \text{ GPM}) = 125 \text{ minutes...or 2 hours and 5 minutes}$

In reality, the output of a 4,000 GPM pump is about 3,200 GPM.

NOTE: Some of the calculations below have been rounded.

Using 23,200 GPM the water usage is 6,400 GPM.

$100,000 \text{ gal} / 6,400 \text{ GPM} = 156 \text{ minutes}$

$156 \text{ minutes} / 60 \text{ min per hour} = 2.5 \text{ hours water supply}$

A 30% recovery rate extends the water supply to just over 3 hours

$2.5 \times 1.3 > 3 \text{ hours}$

If 1,000,000 gal is used in 3 hours, then 3,000,000 gal is used in a 9 hour work day.

The average water well in the S1 field produces about 190 bbls/hour

$190 \text{ bbls/hour} \times 42 \text{ gal/bbl} = 7,980 \text{ gal/hr.}$

With the pit full (1,000,000 gal) in the morning 2,000,000 additional gallons would need to be produced in a 9 hour period.

$2,000,000 \text{ gal} / 9 \text{ hours} = 220,000 \text{ gal/hour}$ needed production

$(220,000 \text{ gal/hr}) / (7,980 \text{ gal/hr/well}) = 27 \text{ water wells.}$

The alternative would be to construct 21,000,000 gallon pits.

On hand supply would then be 6 hours with the need to replenish 1,000,000 gallons in 9 hours.

$1,000,000 \text{ gal} / 9 \text{ hours} = 110,000 \text{ gal/hr}$ replenish rate

$(110,000 \text{ gal/hr}) / (7,980 \text{ gal/hr/well}) = 14 \text{ water wells.}$

To replenish the dry pits over night the water volume would be as follows:

$24 \text{ hours} - 9 \text{ hours} = 15 \text{ hours}$ to replenish the pits

$2,000,000 \text{ gal} / 15 \text{ hours} = 130,000 \text{ gal/hr}$

$(130,000 \text{ gal/hr}) / (7,980 \text{ gal/hr/well}) = 16 \text{ wells.}$

NOTE: If necessary, water wells could be augmented by water tankers. Drilling for water wells and constructing water storage pits is expected to be difficult within the Ratana field due to the hardness of the surface. Water supply within the Ratana field will most likely be from one of the reservoirs in the area.

NOTE: if the above minimums prove to be logistically unfeasible, then operations would necessarily have to be planned around the water supply that IS available.

10.2.10 Civil Works Equipment

A critical point for any major onshore blowout is having the adequate heavy civil works equipment available. If the well is on fire, a D8 bulldozer (or larger) with a Cat Model 57 or Hyster D89C winch is typically used.

The civil works equipment (dozers, cranes, front end loaders etc.) and trucking must be locally obtained. Normally the main civil works equipment problem is the lack of large dozers equipped with a winch. Equipment will need to be maintained and have a working equipment inventory. It may be necessary to mobilize a skilled heavy equipment mechanic with the fire fighters to help keep the equipment running.

Machine shop services needed from custom capping equipment (ex: stingers, crossovers, custom flanges) should be identified and located. The Incident Manager should assign someone to locate these providers.

PTTEP Thailand will need dedicated support personnel working in the areas of transport, material acquisition, logistics, contracting, accounting and communications if a major blowout occurs.

It will be wise, at some point, to gather up the blowout task force and run a test drill on response to a blowout emergency scenario. Minute by minute well reports can be generated to simulate the type of information received from the field to the task force. The response steps are taken including vendor call ups. After the simulation is completed, the exercise is criticized and then edited based on the results of the simulation.

10.2.11 Role of a Rig Contractor

The key to successful blowout control is fast and efficient mobilization of the required support. The following list is not complete but can be used as a reference as to what may be required. The greatest key team member if a blowout is experienced will be the rig contractor, especially if they are experienced in how to acquire local available services, equipment and materials. The rig crew may be needed to assist the well capping specialists. PTTEP Thailand should hold a pre-planning meeting with the rig contractor and discuss these and any additional points:

- Third party billing and purchase order system
- Cash flow assistance (must maintain good credit with local vendors)
- Increased rig crew pay for hazard duty (triple time is not uncommon)
- Added staff from rig contractor to handle logistical duties
- Increase camp space options.
- Spare equipment sources (ex: BOPs & choke manifolds)
- Welding/fabrication sources
- Oilfield supply sources
- Implementation of the fire water system (water wells, pits and pipelines)

10.2.12 Typical Dimensions of Major Firefighting Components

- ATHEY WAGON: three pieces as follows: carriage 26.5' x 8' x 5.5' (15000 lbs), long boom 41' x 4.5' x 2.5' (3000 lbs) short boom 25' x 3' x 2.5' (1500 lbs). Two athey wagons required for a major rig fire.
- FIRE PUMP: integrated on skid (pump capable of 4000 GPM w/425 feet of head): 13' x 7' x 7.5' (10000 lbs). Two pumps required for a major rig fire.
- TRANSFER PUMP: integrated on skid (pump capable of 4750 GPM w/100 feet of head): 13' x 7' x 7' (9000 lbs). Two pumps required for a major rig fire.
- PIPE RACK UNIT: discharge piping and suction lines for pumps: 33' x 7' x 7' (20,000 lbs). One unit required.
- AIR COMPRESSOR UNIT: integrated on skid with priming pump to start fire pumps: 10' x 6' x 4.5' (3000 lbs).

10.2.13 Example Equipment List

The following is an example listing of the equipment and materials that will be required for major blowout scenarios. Not all of these items will be required nor is it a complete list as all blowouts are different and not all needs can be anticipated.

Worst Case Underground Blowout

- The major items that may be required are as follows:
- Cement pump and cementing lines
- Cementing batch mixer or additional mud mixing tank
- Cased hole wireline unit
- Pressure / temperature log, perforators, drill collar severing tool, gyro

- Possible additional stimulation pumps (higher rates and/or pressures required)
- Centrifugal pumps (mud transfer and circulation)
- Suction hoses and mud transfer lines (additional mud tanks and water pit)
- Sack cement and pure bentonite for bentonite – cement – diesel oil – plug
- Medium & coarse LCM materials (KwickSeal, mica, nut plug, ground CaCO₃)
- Additional mud products for quick mix mud (gel, water, caustic, barite, lignosulfonate).
- Additional water supply (possible additional water wells and water storage pit)
- New seismic to map gas flood front (sustained high rate gas flow).
- Re-survey surface location from fixed reference point (severe gas flow)
- Rate gyro run on drill pipe for better relief well target (severe gas flow)
- Initiate relief well planning (severe gas flow, potential loss of surface access).
- Additional mud storage tanks.
- Snubbing unit and tools (drill pipe off bottom, drill pipe plugged, hole in casing).
- Inflatable packer (unable to dynamically kill, due to a hole in casing)
- Handheld radios for site communication

Surface Blowout without Fire or Rig Removal

The major items that may be required are as follows:

- H₂S/Paramedic services: detection equipment, breathing air equipment
- Major civil works contractor to provide: 2 dozers (Cat D7), excavator, front end loader, compactor, 150 ton tracked crane (w/hook & bucket), probable 100 ton hydraulic crane, lube/fuel support, forklifts equivalent to a cat 950 and associated support personnel and skilled operators.
- Welding/fabrication contractor: to provide welders, welding supplies and equipment, nearby fabrication shop
- In country delivery/barge services
- Machine shop: to provide custom toll fabrication and modification
- Pumping/cementing services: to provide cementing unit, batch mixer/blender, spare tanks, pump lines, possible additional horsepower units.
- Medical evacuation services
- Well capping specialists
- Fire pumps and associated equipment
- Blowout technical advisor
- Two air compressors (185 CFM 150 psi) for air tools and engine starting
- Replacement valves, wellheads or BOPs. Additional ram blocks and packers, associated studs, nuts and ring gaskets.
- 75 kg wheel mounted fire extinguishers, additional smaller fire extinguishers

- Fabrication steel including (1/2" – 3/4" round stock, 1" steel plate, H-Beams)
- Dry ice and insulated transport box
- Teflon tape and thread lubricant
- Epoxy thread locking kits
- Cotton Rags
- Bottled drinking water
- Rest location for well capping specialists
- Flare pistol or rifle with flares
- Video and still photographer to record operations
- Location security and location access control of non-essential personnel
- Evacuation of local villagers, livestock
- Water well driller, casing and pumps (additional water supply requirement)
- Portable generators and light plants
- Misc. common oil field supplies and tools
- Ten handheld radios
- Diesel powered centrifugal pumps for fire protection, water transfer
- One reel of 1" to 1-1/8" (25 to 28 mm) soft lay steel cable for tie-downs, snub down lines and winches.

Major Rig Fire

The following services will be required:

- All of the above equipment (1.5.1 and 1.5.2)
- Support mats for pumps and equipment
- Four D8 equivalent dozers (prefer low ground pressure D8N dozers with cat Model 57 winches)
- Two cat Model 57 winches or those compatible with the dozers on location with power forward/reverse and no neutral (free spool) position
- Large walking crane > 150 ton with large boom, hook and bucket
- Two large cat 235 excavators
- Two cat 950 or 966E front end loaders with bucket and forks
- 2", 3" and 4" A36 steel plate (1m square)
- Structural steel: channel iron, box tubing, H beams, round tubing
- Air conditioned rest and paramedic stations
- River rock and gravel for location stabilization
- 6" pipeline pipe and 8-5/8" – 9-5/8" 8RD casing
- Water pumps for pipeline
- Light plants and generators

- Carpentry crews and materials (plywood, boards, nails, etc.)
- 50 ton rough terrain crane w/slugs for assembling firefighting and capping tools
- Pipeline welding machines
- Anchor setting machine and anchors (auger type)
- Construction concrete and rebar
- UPS power supply for operations center
- 100000 psi discharge lines from Halliburton, Schlumberger or BJ (steel or Coflex)
- Additional horsepower from Halliburton, Schlumberger or BJ
- Over 50 handheld radios with extra batteries and multiple rechargers
- Over 5 long range mobile units
- Two international phone lines as the on-scene command center
- 1", 3/4" and 1/2" wire rope and cable clamps for slugs
- Centrifugal trash pumps to pump out sumps, excavations and cellars

Normal Oilfield Services

Other considerations include such services and supplies as are normally used in oilfield operations.

The following is a partial list of the types of services or materials which may be needed.

- Oilfield Services and Materials:
- Mud Supplies and Mixing Equipment
- Civil Works (earth moving)
- Water Tanks
- Environmental
- Rental Tools
- Communications
- Cementing Stimulation Services
- Slick Line
- Open hole E-Line
- Cased Hole E-Line
- Well Testing
- Wellhead Maintenance
- Hot Tapping

Other Requirements

BOP and well control equipment will likely be rented locally but it may be necessary to bring in a specialized capping stack from Houston (Weatherford).

10.3 BLOWOUT SCENARIOS AND COMMENTARY

10.3.1 Underground Blowouts

Underground blowouts are the most common type of blowout. These blowouts generally occur when loss of circulation is experienced while circulating out a kick.

10.3.2 Basic Control Procedures

It is common for field personnel to fail to recognize that an underground blowout is occurring since many times they are focused on curing loss circulation. The following are signs of underground flow:

- Initial drill pipe and casing pressure increase followed by decrease. Typically, drill pipe pressure will drop to zero and then increase and casing pressure may not change very much.
- Gas, oil or salt water to surface on drill pipe caused mud jetted out of drill pipe by flow and replaced with blowout fluids (no float).
- Unable to get mud returns with blowout fluids at surface in annulus. Mud carried out in loss zone by mud.
- Able to strip up or down with no change in annulus pressure. Controlling pressure is fracture pressure or pore pressure at the loss zone.
- Thermal anomalies seen in temperature log. Higher temperatures seen opposite shallower loss zone (flow from bottom). Lower temperatures seen opposite loss zone (flow from top rare).
- No direct indication of pressure communication between drill pipe and annulus.

Underground flow begins when normal drill pipe circulation pressure is lost. It is common for this to occur when the leading edge of a gas kick is circulated past the last casing shoe or hits surface (choke line restriction). After underground blowout gas flow starts, mud is quickly jetted out of the well bore. If pumps are shut down the drill pipe pressure will stabilize slightly above the annulus pressure. This difference results from flowing frictional pressure drop in the annulus and/or the hydrostatic of gas lifted water. The greater this difference the higher the annulus friction or fluid density will be. If the bit is significantly off bottom and the drill pipe string is free, the drill string should be stripped through annular to bottom to facilitate the control. This is easily done, as no mud needs to be led out of the well when stripping into an underground flow. This is facilitated if there is a drill string float. If a DP float is not installed, BPV can be installed to allow making up connections, however, BPV in the string will limit wireline work and should be avoided if possible.

In the underground blowout it is often necessary to run logs in the DP so obstructions should be avoided.

When underground flow occurs, run a pressure/temperature log in the drill pipe to locate the loss zone and define flowing bottomhole pressure. Blow nozzles out of bit to minimize pressure drop and risk of nozzle plugging with loss circulation materials. If not possible, consider perforating or severing the drill collars. However, perforations in DC are at best difficult to accomplish as the bore limits the size tool that can be run via wireline. Consider running a rate gyro for a better relief well target or in case the well is sidetracked after control is gained.

Mobilize additional mud storage tanks if necessary. Mobilize cementing batch mixer if available. Mix and store at least one additional hole volume of mud on location. While mixing mud, bullhead water down the annulus to loss zone to minimize annulus surface pressure and keep possible H₂S off of casing, wellhead and BOPs. This will assist in interpreting the temperature log by defining a

temperature gradient at loss zone. Fracture extension pressure can be estimated from surface injection pressure over water hydrostatic to loss zone.

Slow the annulus rate and continue annular water injection with cementing pump. Pump down drill string at 90% of maximum possible rate using rig pumps with water until pressure stabilizes. Record stabilized pressure and rate. Increase the pump rate to maximum and record stabilized pressure and rate. The stabilized pressure on drill pipe is a function of the annulus two-phase flow hydrostatic and friction. If single flow can be achieved in the annulus, the well can be dynamically killed with the rig pumps. The drill pressure for single phase water flow can be accurately determined. If this pressure is nearly achieved during the test, the well can be easily killed using kill weight mud instead of water. Loss circulation materials can be added to the mud to help get a static kill after the pumps are shut down. If a dynamic kill with mud or water is not achieved, the recorded stabilized two phase flow pressure developed during the attempted kill in combination with the results of the pressure/temperature log can be analysed to determine what would be required. Gunk squeezes (diesel oil-bentonite-cement) or high density pills (barite pills) could also be used depending on the results.

10.3.3 Surface Blowout/Not on Fire

During drilling, a kick must be taken before the well can blowout. Generally, all surface blowouts are a result of equipment or operational failure of the BOP system, wellhead equipment or near surface tubular during a kick. Some blowouts are a result of an underground blowout breaching to surface. Surface breaching generally eliminates surface access making a relief well the only viable option. Surface intervention of a breached well is only possible if the breached is stable and downwind of the well. And flow rate is low. A surface blowout that is not on fire would be either in the BOP equipment, wellhead equipment, through the drill pipe or during testing. These are the four surface blowout scenarios that will be evaluated.

Likely Surface Blowout Scenarios

Flow may not ignite if low heat content gas is produced (low C_1 fraction, N_2 and CO_2) and particularly if free water is produced with the gas. Dry gas production makes ignition of a blowout very likely. High internal corrosion/erosion rates (combination of high velocity, CO_2 and free water) can complicate control. H_2S and CO_2 may be present in very low concentrations.

Annular Blowout Flow

If the annular blowout flow is occurring above the wellhead, then a failure is at the BOP flanges, bonnet seals, ram packer, steam packing or outlets has occurred. Generally, the failures are not catastrophic but start as leaks that cut-out the affected BOP area and become blowouts. Quick detection and proper response can keep the problem from getting any worse. The first option is to isolate the leak if possible by closing the lower rams. Leaks can then be plugged by pumping plugging materials through the kill lines. In some limited cases, gas hydrates form a temporary plug, then melts, and the leak restarts, and then hydrates re-form. This cycle of leakage and the formation of hydrates, most probably will cause the leak to worsen due to erosion. The application of water ice (better) or dry ice (solid CO_2) at the leak can help hydrates form or reform and keep them from melting. Pressure can be temporarily relieved down the choke line while preparing to fix the leak and/or re-torque flanges. In all these cases response time is limited. Action must be taken at the well site immediately. Ultimately, severe cut out of equipment can eliminate all of these options. Removal and replacement of cutout equipment would be required. This could require removal of the drilling rig and would require a well capping specialist.

A minor leak at or below the wellhead could also be controlled, as discussed before, with plugging materials or dry ice induced hydrates.

Drill Pipe Blowout Flow

Most drill pipe blowouts occur either while tripping into swabbed in gas or from failure of surface safety valves and pump in lines. It can be impossible to close a ball type safety valve against strong flow. Drill pipe blowouts can be prevented by using drill string float valves. An Oil Base Mud will increase the risk of a drill pipe blowout.

Tripping into oil mud saturated with gas leads to drill pipe blowouts if a float valve is not used. Immediate well site control could be accomplished by stabbing a safety valve. Leaks in threads could be hydrated off with dry ice or plugged with junk shots.

A method used to control drill pipe flow is by stabbing a double ram BOP with inverted slip ram under inverted pipe ram, drilling spool, single blind ram, 2 m long bell nipple.

- Tool joint is spaced out between the rams, diverter and pump in lines are hooked up to the spool.
- The inverted slip ram is closed.
- The inverted pipe ram is closed
- The diverter line opened and the blind ram is closed
- The diverter line is choked back and control is accomplished conventionally through the pump in line.

Small BOPs (7-1/16") have been successfully used to cap drill pipe flow in this manner with drill pipe suspended in rotary or BOP. A hydraulic crane has been used to place the BOPs over the drill pipe with the rig in place. With are on space out, the drilling spool can be eliminated by using the outlets on the upper BOP. BOP equipment as small as 4 1/16" have been used successfully on small drill pipe and tubing blowouts. On lower pressure blowouts the inverted slip ram can be dropped as the inverted pipe ram that will catch on the upset or collar.

If the well broaches to surface, it is imperative that wellbore pressure be released before the rig is cratered. Rigs have been lost because the location was abandoned with the BOP still shut in on the annulus with the well broached to the surface. The first step to take is to open the choke line directly to a flare line. If the flow in the broach is not impacted, then opening the BOP stack and letting the well blow vertically must be considered. Ideally, the rotary slips and bushings should be removed and drill string slacked off nearly totally on bottom with a tool joint rested against a ram. Remove all loose tools away from rotary and drop the travelling block out the V-door or pull up high in derrick. Shut down all sources of ignition, evacuate rig and open all rams from BOP remote station to let well flow vertically and drop the drill pipe. This will likely result in the well bore bridging. Most open hole blowouts end from natural formation bridging. Bridging can be induced if wellbore pressure is suddenly lowered and annulus is partially filled with helically buckled drill string. Many cratered rig blowouts requiring relief well control have been controlled in this manner by the wellsite crew.

Whenever there is a gas risk at surface, firefighting equipment should be positioned and manned (example: well testing). The rig fire main should be charged and fire hoses in place and operated. The fire hoses need to be coupled away from the potential fire area and positioned upwind from the well head near the large wheel mounted fire extinguishers. Men operating the fire extinguishers can then go in toward the fire under protection from water spray from the fire hoses. Fire hoses and men will not burn if a water curtain is maintained between them and the fire. A water spray can prevent unwanted ignition. The large fire extinguishers can extinguish smaller well fires and used in combination with water from the fire hoses.

The key to successful use of the large fire extinguishers is to:

- Fully stretch out the discharge lines prior to operation.
- Work as close to the fire as possible on an upwind size.
- Start with water to cool area around fire prior to opening valve on extinguishers.
- After cooling the fire as much as possible with available water, open at least two extinguishers simultaneously and direct powder at base of flames.
- Fully discharge extinguishers and continue applying maximum available water to prevent re-ignition.
- If the fire does not extinguish or re-ignites, then there is insufficient water flow out the hoses. Larger pumps, more hoses or fire monitors are needed.

Ideally, the rig contractor should have a team with the assigned responsibility for this activity. At least two men are needed on each fire hose, two men on each extinguisher and one man in heat reflective asbestos dress as a rescue man. The other should wear normal safety equipment, long sleeve cotton coveralls and cotton gloves and be thoroughly soaked with water. A wet cotton towel stuffed around the head, neck and face and into the coverall will provide additional protection. Practice drills of firefighting team should be considered.

Capping & Control Procedure (most likely Blowout)

Major surface leaks during kick handling procedures in the BOP equipment should be the most likely type of surface blowout.

The use of junk shots to plug surface equipment leaks should be understood by wellsite supervisory personnel. Successful junk shot application is time dependent as the leak opening always grows. A junk shot is accomplished by removing the check valves (to prevent line plugging) and loading 1 to 2 meters of kill line with rope fiber and walnut hull. The best fibers are the Kevlar or polypropylene types (higher tensile strength than hemp or cotton). If rope is to be used, the rope pieces should be 6" long 3/8" diameter, and frayed with tight knot in the middle of the rope. The walnut hulls should be medium and coarse materials. Mud loaded with 10 ppb medium Kwik-seal should be used to displace the junk shot (Kwik seal is a blend of fiber, granular and flake material). The junk shot will bridge and seal the leak allowing conventional control operations to continue. Additional junk shots can be pumped at times to re-seal the leak. Large leaks have been controlled by pumping golf balls a head of the junk shots. A 5 gallon bucket of pre-cut rope and other bridging material can be kept on the rig to quickly inject a junk shot to seal a surface leak. Time is saved if this is done and a rig scavenger hunt for sealing materials is not required.

Leaks can be worked on or stabilized until a fix is possible by relieving pressure. Flow out wide open chokes down the flare line should be considered. It is better to open the well up on flare line than to allow pressure containing equipment to cut-out.

The ram blocks of Cameron type "U" preventers can be replaced by well capping specialists while the well is blowing out vertically. Steps taken involve opening all BOPs to eliminate any back pressure, applying water deluge, hydraulically opening the bonnets and replacing ram blocks. This is possible as the high velocity gas flow produces a vacuum from a Venturi effect in the BOP and the bell nipple located above the BOP to be repaired. (The bonnets can be remotely hydraulically operated and quickly opened. The Venturi effect draws air into the BOP and very little gas escapes.)

10.3.4 Surface Blowout/Well on Fire

A hot fire causes rig collapse within minutes. Melted steel and debris will cover the BOP and wellhead causing severe damage to the wellhead. If this happens, the well most probably will have to be capped on exposed casing. Blowout control operations can take weeks

10.4 CAPPING STRATEGY

10.5 SURFACE INTERVENTION, FIREFIGHTING & CAPPING STRATEGY

It is not possible to discuss every eventuality which may arise during an offshore blowout. However, a general discussion of the equipment and techniques typically used on a major offshore blowout/fire is needed. Appendix B offers a general discussion regarding capping operations. The following intervention techniques are those which may be employed after the initial mobilization and set-up of the primary support vessel has been completed.

10.5.1 Debris Removal

The initial phase of the intervention will involve clearing damaged or unnecessary equipment from the structure. This is done to provide working room as well as to remove valuable equipment from danger. The intervention team attempt to re-board the structure under the covering water spray from either a tie-in of the primary firewater ring or from the primary support vessel. Once on board, the intervention team will assess the situation and proceed accordingly. The crane on the support vessel can be used to remove all equipment which is accessible. In certain situations it may be possible to use the existing platform crane(s). This may not be feasible since the crane may be damaged beyond repair or it may not be practical to re-connect power to the crane.

10.5.2 Fire Control

To safely deal with an offshore blowout, the intervention team must have the capability to apply large volumes of water. This should be done to cool the area and allow wellhead access or to aid in the prevention of ignition while working in proximity to the flow. Portable monitors will be placed at the point where covering firewater is needed. There are three feasible sources of firewater. They are from:

- Existing firewater ring (provided it is operational)
- Firewater pumps on standby boats or barges (vessels of opportunity) or
- Portable firewater pumps (from well control vendor or others)

During the intervention project, usually following debris removal, attempts will be made to place firefighting monitors (outlets) on the structure at points that will be determined by the incident, per Figure below. If possible, attempts may be made to utilize the existing deluge piping on the structure. This has been accomplished on platform fires and blowouts in the past and has proven very beneficial to the project. If the existing firewater ring is not energized from the pumps on the platform, an external tie-in of portable pumps at the splash zone (boat landing) is recommended. This is best accomplished if a vertical riser is in place beforehand. However, this can be installed in by the intervention team if necessary.

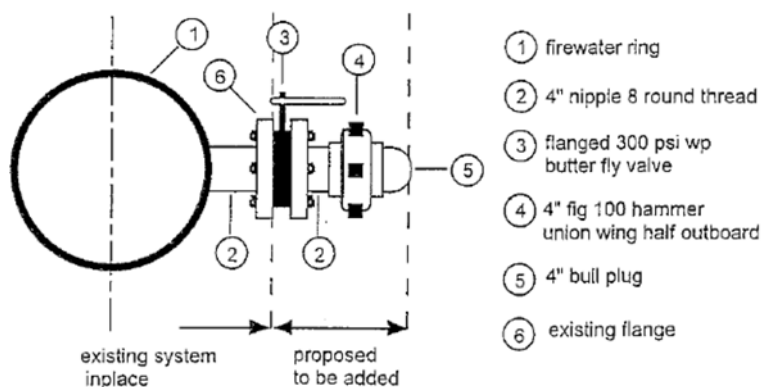


Figure Example of a tie-in to the firewater ring for portable monitors

Portable firewater monitors (type rated at 1,200 gpm) placed on the structure will provide precise placement of water for cover and cooling purposes. If the firewater ring cannot be utilized, an alternate will be to install temporary conduits such as large, low pressure hoses from the support vessel to the monitors on the structure. If space and conditions allow, portable firewater pumps can be placed on the structure and their suctions charged by the pumps on the support vessel.

Firewater application from standby boats is a viable option and has certain advantages and disadvantages. One advantage is that the boat can be mobilized to the site and used if the platform is abandoned. Therefore a re-start of engines and re-boarding of the facility may not be necessary. Firewater supply from a barge or boat necessitates that the boat come alongside the burning or blowing well platform. This places the boat and the crew closer to the problem and increases the potential for injury and damage if proper procedures are not employed. Firewater support from floating platforms is controlled by the wind and seas. Precise application is required to protect the intervention personnel, and wave action (greater than $\frac{1}{2}$ to $\frac{3}{4}$ m) may prevent the boat from applying the water stream onto the point of interest with sufficient reliability. Therefore this method may require more stringent weather windows for close work by the intervention team.

Portable pumps and marine manifolds can also be deployed to provide firewater for the intervention efforts. This equipment will have to be flown in from the USA or sourced in the local market. Mobilization and rig up takes time. While this is underway the situation can worsen (structural damage, wellhead leaks, etc.). This pumping equipment and specially designed marine manifolds will be used for the purpose of applying firewater for prevention of subsequent damage and to cover the intervention efforts. If the primary support vessel has no firefighting capabilities, these pumps can be used exclusively. If other firefighting capabilities are available, they can be used in conjunction with the onboard pumps.

10.5.3 Moving Onto the Structure

Once sufficient working space is made an available on the structure, operations will be undertaken on the structure. The initial and supporting approaches with the MSV or crane barge will generally be determined by wind and tide direction.

Water monitors will be placed at the working area for more precise water application and protection of the crews and equipment. All operations near the wellhead must be done with a protective and/or cooling water spray cover. In some instances, portable cranes will be assembled on the deck of the structure. This will in turn be used for further debris removal, precise equipment placement and eventually for capping the well. In previous operations it has been possible to place a large tracked crane (80 ton) onto the deck of the well platform.

10.5.4 Gaining Wellhead Access

With operations established on the structure, final debris removal can begin which will allow wellhead access. This may require more cutting which can be done by one of the methods previously mentioned. If the well is on fire, all heated metal debris must be removed before the fire can be extinguished. A Venturi tube may be placed over the well flow to raise the ignition point and consolidate the flow. This will allow better access to the wellhead and provide a means to cool the surrounding structural steel components. Fires which cause major structural damage sometimes require extensive fabrication projects to re-build a working platform around the wellhead.

10.5.5 Extinguishing the Fire

Once clear access to the wellhead has been established, efforts will be made to configure the flow into a single vertical stream (if not so already). Many fires can be extinguished using water alone. Unless obviously unsuitable, this technique will be attempted first. The Venturi tube may be used in conjunction with the water application to improve the chances of success. If these attempts fail, explosives may be used to extinguish the fire (this is a rare occurrence in offshore operations however). Unless major structural damage is imminent the fire may be left burning until all preparations have been made for capping. This is done as a pollution control measure.

10.5.6 Wellhead, Tree and BOP Removal

With the fire either extinguished or directed through a Venture tube, closer inspection of the wellhead equipment can be made. This inspection will determine whether the existing equipment can be used to attach capping devices or if all or part of it will need to be removed. If nothing can be salvaged, the entire wellhead and all casing strings can be cut off. More detail can be found in Appendix b: Capping Operations.

10.5.7 Control Operations

Control operations usually fall into one of two general categories; shut-in or divert. If for some reason the well cannot be shut-in, it is common practice to divert the well and utilize a snubbing unit to either fish the tubing/drillpipe or to snub in a kill work string (e.g. place a tubing string on bottom for kill operations).

Depending on the severity of damage, extensive structural repair may be necessary before this type of work can proceed. If the well is to be diverted, flow lines and choke manifolds can be set in place allowing safe operations for construction while the well is on diversion.

There are infinite scenarios for kill operations so detail is not possible in this section. Kill operations will fall into board categories as follows;

- Bullhead after shut in.
- Dynamic kill through a work string.
- Circulate out after shut-in.

The circumstances of the event will guide the intervention team to the solution that best fits the conditions at hand. Much work may be needed to be in a position to kill the well. Careful evaluation of the integrity of the wellhead equipment on the well and the downhole equipment is a must. It is often the case that judgment is the only means to guide the kill operation. A general rule for kill operations is that the stresses induced in the kill should be kept to a minimum if there are any doubts with the pressure control equipment on or in the well.

Auxiliary vessels such as pump boats and fluid handling vessels may be required if the structure will not support or accommodate such equipment. If snubbing equipment or other wellhead

supported equipment of significant weight is to be utilized, additional fabrication may be necessary to insure structural integrity.

10.5.8 Support: MSV, Goods and Material Services

PRIMARY SUPPORT VESSEL: The primary support vessel is the platform from which the intervention effort will be directed. Conventionally moored derrick/pipelay barges are generally the vessel of choice for primary support. This type vessel possesses several features that are beneficial to the overall success of the project.

These barges are available with adequate open deck space to support even the most complex projects. Simultaneous projects such as fabrication, modifications and repairs can all be undertaken on deck. This significantly reduces the logistics of monitoring and supervision of these tasks.

Most derrick/pipelay barges are equipped with “jet” pumps mounted below deck. These pumps, normally used for pipe laying operations, are typically rated at 3,000-5,000 GPM @ 400-600 psi. Some barges have modifications that allow these pumps to be used for firefighting purposes. If not, the modifications must be made quickly. Where elevated structures are involved, these pumps can be used to supply water to other pumps mounted on the structure itself

The cranes on these type vessels are essential for debris removal and equipment/personnel movement to and from the structure. It is not unusual for crane lifting capabilities to far exceed actual needs. The heaviest lifts likely to be encountered are the removal of a complete drilling package from the platform. However, barges with lifting capabilities of 500 to 700 tons are sometimes required to ensure adequate boom length and deck space. A 300' boom length may be required to reach the uppermost portions of the structure while allowing a safe horizontal offset distance. A typical crane barge with a 300' boom offset 150' from the structure is only capable of lifting approximately 25% of its maximum rating to a height of 240'. Barge with larger dimensions also provide added stability which will allow work to proceed during moderately rough seas.

The additional expense of the larger barge is justified given the limited availability of this type vessel. If a smaller barge is contracted and conditions develop that make it inadequate, a larger vessel may not be immediately available. These are obviously very undesirable circumstances. Another benefit of the moored barge is its ability to be removed from proximity to the well in an emergency. This is often necessary due to changing well or weather conditions. Adequate towing capabilities (tugs) should be at hand to assist if needed. The derrick/pipelay barge should be mobilized to the location immediately. Firewater pumps and accessory equipment can be mobilized on a utility boat if required. Once on location, anchors can be set for the barge, the equipment can be off loaded from the utility boat and assembled prior to moving close to the structure.

SECONDARY VESSELS: In addition to the primary support vessel and pollution containment vessels, at least two crew boats and one utility (work) boat will be needed.

FABRICATION PERSONNEL AND EQUIPMENT: A minimum of two certified welders will be needed for various fabrication projects. Each should be fully supplied with necessary equipment such as welding machines, cutting torches, grinders, chipping hammers, wire brushes, etc. An adequate supply of safety equipment ordinarily used during fabrication projects such as goggles and face shields will be required.

ROUSTABOUTS: A roustabout crew will be needed for various tasks such as fabrication and rig-up of pumps and lines. A crew consisting of one supervisor and five roustabouts should be contracted.

MATERIAL: A considerable amount of fabrication material will be needed for various tasks. The material in the following list will generally provide an adequate amount for the initial requirements:

- 200 sheets – 2' x 8' galvanized corrugated tin (10 gauge or thicker)

- 150 lb. of bailing wire (soft wire for attaching fire shields)
- 30 joints – 2-3/8” tubing (junk)
- 12 pieces (500 ft²) – expanded metal grating
- 750 ft – 2” x 2” x 1/4” angle iron
- 500 ft – 3” x 3” x 1/4” angle iron
- 2 sheets – 4’ x 8’ x 1/4” steel plate
- 1 sheet – 4’ x 8’ x 1” steel plate
- 500 feet – 1/2” softlay cable (6 x 36) with 50 clamps
- 500 feet – 3/4” softlay cable (6 x 36) with 50 clamps
- 500 feet – 1” softlay cable (6 x 36) with 50 clamps
- 500 feet – 1-1/8” softlay cable (6 x 36) with 50 clamps
- 250 feet – 1/2” cold rolled bar

AIR COMPRESSOR: Two 255 CFM, 125 psi air compressor each with 300 ft of 2” 200 psi WP hose and spare end connections. These will be required to supply air for starting pumps and operating other pneumatic tools later in the project. Available through local specialty rental companies or may be available on the primary support vessel.

LIGHT TOWERS: Self-contained diesel powered light towers should be ordered to facilitate fabrication projects which may extend into the night, available from specialty rental companies. Primary support vessel may have adequate lighting.

ABRASIVE CUTTERS: Ultra-high pressure (30,000 + psi) cutters which use abrasive material such as frac sand, slag or crushed garnet. Used for debris wellhead and casing cutting in explosive atmospheres, available from Halliburton (Duncan, OK).

LATHE CUTTERS: Portable lathe type dye cutters may be required for circumferential cuts on casing strings.

EXPLOSIVES: Explosives may be necessary for debris removal and possibly for extinguishing the fire. NOTE: Since Abrasive Jet Cutters have been introduced explosives have been rarely used, therefore this is mentioned as a contingency only.

TRASH PUMPS: Portable air operated diaphragm type pumps may be needed for various fluid transfer tasks on the structure. Small pumps such as Wilden 3” are preferred since they provide the necessary mobility, available from specialty rental tool companies.

PORTABLE CRANES: it may become necessary to install a portable crane on the structure for capping and/or debris removal, available through various marine crane rental companies.

PNEUMATIC WINCHES: Large pneumatic winches, or “air tuggers”, may be needed for capping and/or debris removal, available through specialty rental companies.

PNEUMATIC TOOLS: Impact wrenches, drills, grinders, pneumatic hacksaws along with hoses, sockets, bits and various other accessory pieces. These are available from most oilfield supply outlets.

HYDRAULIC TOOLS: Torque wrenches, nut splitters and portable power jacks. These are available from pressure testing companies and specialty rental companies.

SURFACE EQUIPEMNT: BOPS's, chokes/manifolds, closing units, chicksan lines etc. Available from oilfield rental tool companies.

10.5.9 Personnel Safety and Medical Services

The highest possible standards must be maintained with regard to personnel safety at all times. The well control intervention team will constantly strive to insure the safest possible working environment based on their previous experience with similar situations. However, risks will inevitably be involved with some operations. The well control team must work with TOTAL to properly manage and minimize these risks.

EMERGENCY MEDICAL EQUIPMENT: There should be trained medical personnel on location with equipment to treat trauma. Their expertise should cover burn treatment in addition to typical oil-field related injuries. Certified EMT, personnel are available through some oil-field safety companies such as CAMCO, SABER, etc.

MEDIVAC SERVICES: A medical evacuation helicopter should be on alert at all times to transport seriously injured personnel to near-by medical facilities for treatment. This service should be able to provide advanced life support during transit.

10.5.10 Communications

Efficient communication is essential to the success and safety of the project. A central dispatching system must be arranged to control the movement of equipment and personnel (existing system or installed after the incident occurs). This is best handled by a central base station operation where a radio operator continually monitors and dispatches necessary services in conjunction with the TOTAL project control procedures and purchasing specifications.

An independent communication link should be established between the location and the coordinating TOTAL office. Voice and data transfer capabilities will be necessary.

On-site communications are vital. Portable radios should be provided with a dedicated frequency to be used by the personnel at the location.

10.5.11 Fabrication

If a major fabrication project becomes necessary, the most expedient method may be to have it undertaken onshore. In some cases the offshore construction barge or MSV may be able to handle the job. An evaluation should be conducted to assess the need for major fabrication projects as soon as feasible and make the decision to fabrication onshore or offshore. Regardless of the choice, a competent fabrication shop should be contracted to begin the projects(s) immediately.

10.5.12 Machine Shop Services

There may be occasion to construct or repair precision components of various pieces of equipment used in the well control effort. It is recommended that a full service machine shop be available on a 24 hour basis during the project.

10.5.13 General Support

There should be a pool of resources that cover labor and transportation as well as procurement and expediting to support the well control effort. One should not lose sight of the fact that, in the end, all costs will have to be accounted for and justified. Tracking of material and documentation of purchasing will be essential tasks that can best be done at the time of procurement rather than after the fact.

10.5.14 Weather Monitoring

A recognized weather reporting/forecasting service should be employed. Daily weather reports should be made available to the TOTAL coordinating office and the personnel on location. Prior knowledge of impending weather changes can be a valuable tool for operational planning and safety.

10.5.15 Personnel Quartering

If adequate facilities are not present on the primary support vessel, arrangements will have to be made for housing and feeding of the personnel on location. A 24 hour galley may be necessary as fabrication and repair projects will likely be on-going around the clock. Laundry services will be needed for personnel staying on location. It is expected that these needs will be met by contracting a "floatel" or by using adjacent TOTAL facilities.

10.5.16 Firefighting Equipment

The major well control vendors have an inventory of specialized tools and equipment ready for immediate mobilization 24 hours a day. The following is a partial listing including a brief description;

- Fire pumps – Driven by diesel engines with centrifugal high volume low pressure firewater pump. (Example: Detroit Diesel 8V-91, 540 HP turbo charged engine with centrifugal pump delivering 4 to 5,000 GPM @ 200 psi) Each pump is mounted on an oilfield skid with protective roll cage and single lift attachment point, forklift attachment and loading hitch for rolling tailboard transport.
- Suction manifolds, suction and discharge hoses.
- Marine manifold for installation on marine vessel deck. The main components of the marine manifold are.
 - 1 ea., 10" x 20' steel fire monitor manifold w/ 4 ea. 4" flanged outlets, 1 ea., 10" flanged inlet, 4 ea. 4" butterfly valves, 4 ea. 4" Fig. 100 hammer unions.
 - 3 ea., 10" x 21' flanged supply line sections
 - 1 ea., 10" x 16' flanged supply line section
 - 1 ea., 10" x 6" 90° flanged elbow
 - 4 ea., 6" x 4' steel pipe extensions w/90 ° ells for use with suction hoses
 - 4 ea., 1000 GPM water cannons
- Fire monitors: 2,000 to 6,000 GPM.
- Casing clamps: for use in various capping procedures.
- Venturi tube: to consolidate and raise the flow and/or ignition point.
- Portable toolhouse – containing complete set of hand tools from 1/4" end wrench to 48" pipe wrench for maintenance and repair. Complete set of hammer wrenches and brass hammers.
- Portable Lathe Type Cutters – Used for making circumferential cuts on casing strings.
- Explosives – All necessary equipment for demolition. A fully-licensed explosives expert will be required.
- Nomex Protective Clothing – For use by personnel working in proximity to the combustible flow or fire.

- Communications – Hand held radios for use by personnel on location
- Foam/Dispersant Application – For fire extinguishing or protection

10.6 CAPPING OPERATIONS

Capping operations are an integral part of most blowout intervention projects. In many instances, capping of the blowout well is the primary objective, the first major step in regaining control of the well.

The term “capping” is sometimes loosely used to refer to the whole process of surface intervention. The more precise definition, used here, is the placement of a competent pressure control device onto the blowout well under flowing conditions. Once the new control device (BOP, valve, etc.) is positioned over the well, there must be a means of attaching the device so that pressure integrity can be regained.

Regardless of its components, the control device is typically referred to as the capping stack or capping assembly. The magnitude of the pressure which the control device will be expected to withstand is the Maximum Anticipated Surface Pressure (MASP). For capping operations, the MASP is the maximum shut-in wellhead pressure plus externally applied pressure (e.g., pressures exerted while bullheading) multiplied by a safety factor (e.g., 1.25). The MASP with appropriate safety factor should be compared to the working pressure of the equipment. Temperature can be a consideration, as the BOP may need to be de-rated for the flowing wellhead temperature. This is especially true for HTHP wells. Capping operations also include preparing the wellhead for placement of the capping stack. This sometimes involves removal of part or all of the existing wellhead/BOP stack.

Important factors to consider in planning a capping operation include:

- Forces exerted on the capping stack as it is brought into the flow.
- Best method to insure full control of the movement of the capping stack when it enters the flow (prevention of turning and swinging).
- Measures to minimize the potential for ignition during the capping operation and contingencies for ignition if it does occur.
- Through bore size (ID) of the capping stack sufficient to allow subsequent work.
- Functions required of the capping stack (e.g., outlets needed for diverting the flow, pumping into the well, pressure monitoring and snubbing operations).
- Best attachment method for securing the capping stack to the well.
- Pressure and temperature ratings required to control the well throughout all phases of the well control operation.
- Forces exerted on the capping stack during the post capping operations such as snubbing and bullheading.

Proper planning of a capping operation must take into account the mass flow rate, combustible nature of the flow, wellbore geometry and operations to be undertaken in the ensuing post-capping phase of the project. The methods used for capping can generally be divided into three techniques:

- Capping to a flange.
- Capping to a stub by first installing a wellhead.
- Capping to a stub by swallowing the stub.

This chapter provides an overview of the steps necessary to safely accomplish capping operations using these three techniques.

10.6.1 GAINING ACCESS WITH THE ACV

Before the actual capping process can begin, well access is necessary. Direct access is usually denied because of structural damage to the drilling structure or platform. Debris, which may include melted masses of metal, must be removed before the intervention at the wellhead can begin. The All-Purpose Capping Vehicle (ACV) was developed for the purposes of working on blowing wells that can also be on fire. ACV applications include:

- Removing debris using hooks and rakes.
- Conveying special tools, such as abrasive jet cutters, Venturi tubes and stingers.
- Placing explosives at a “safe” distance for severing or extinguishing the fire.
- Hoisting and stabbing-on capping assemblies.
-

Figures F.1 and F.2 illustrate the two main types of ACV's Figure F.3 shows end attachments often used in well control operations.

In the early years of the well control business, Athey wagons were employed to drag damaged equipment from the well. They were generally used to remove debris and only rarely to convey tools to the wellhead. The name ‘Athey’ is in fact a misnomer, as it actually refers to the leading manufacturer of a certain type of steel track used for rig moves, or for moving heavy lifts in rough terrain, though the older name is still commonly used by capping companies. All-Purpose Capping Vehicle or ACV better describes the capabilities of the modern vehicles.

There are two basic versions of the ACV: conventional and hydraulic. The conventional unit relies on the power of a bulldozer and its tail winch to move and position the boom. Figure F.1 shows the conventional ACV hooked up to a bulldozer. The tail winch articulates the boom while the dozer is used to position the wagon.

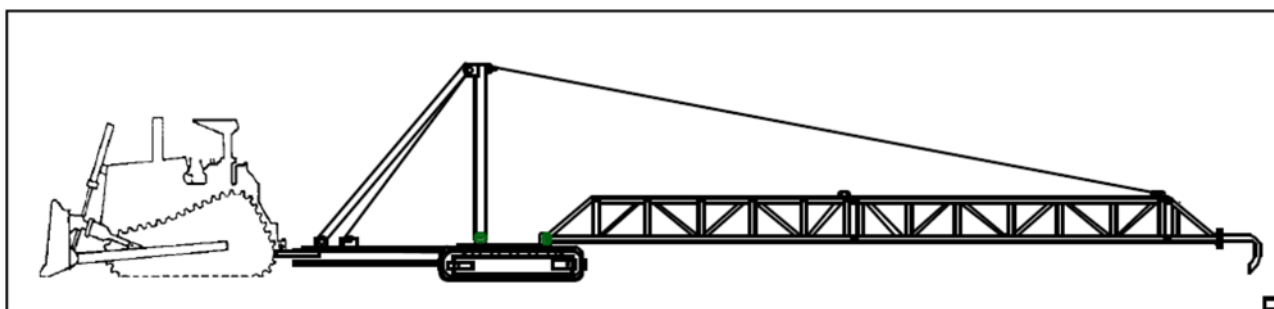


Figure F.1 Conventional ACV with End Hook Attachment

The hydraulic version of the ACV was developed primarily for the purpose of stabbing-on BOP and conveying tools that require precise positioning, such as the abrasive jet cutter. In these applications, hydraulic winches provide fine control of the boom articulation. Wild Well Control, Inc. has developed a hydraulic ACV that is secured by a bulldozer, which provides movement, hydraulic winches to control the boom angle and a set of winches at the front of the vehicle for pulling or snubbing on BOPs. One drawback of the hydraulic ACV is the requirement of a power pack to operate the hydraulic winches, and this increases the overall air shipping weight and volume. However, all components break down into small lifts that will fit on almost all commercial cargo planes. Figure F.2 illustrates the hydraulic model of the ACV equipped for a stab-on manoeuvre.

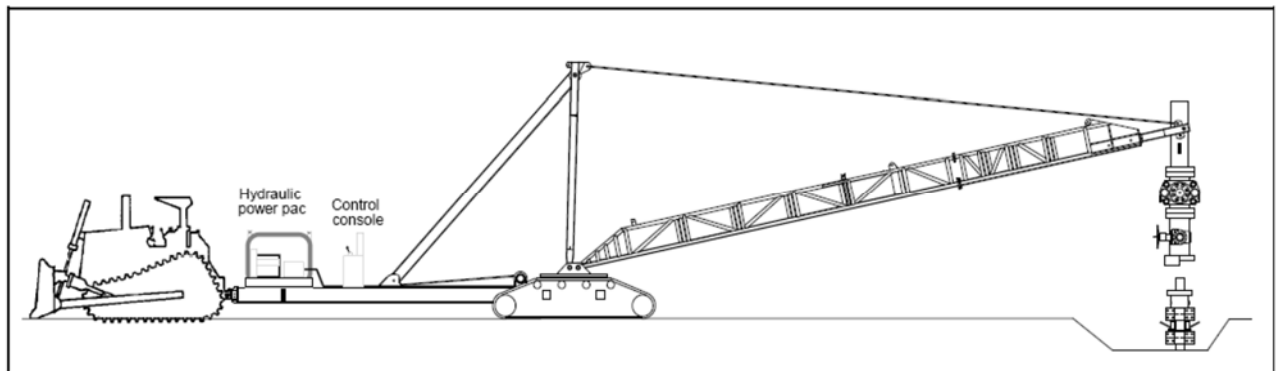


Figure F.2 Hydraulic ACV Stabbing-on a BOP

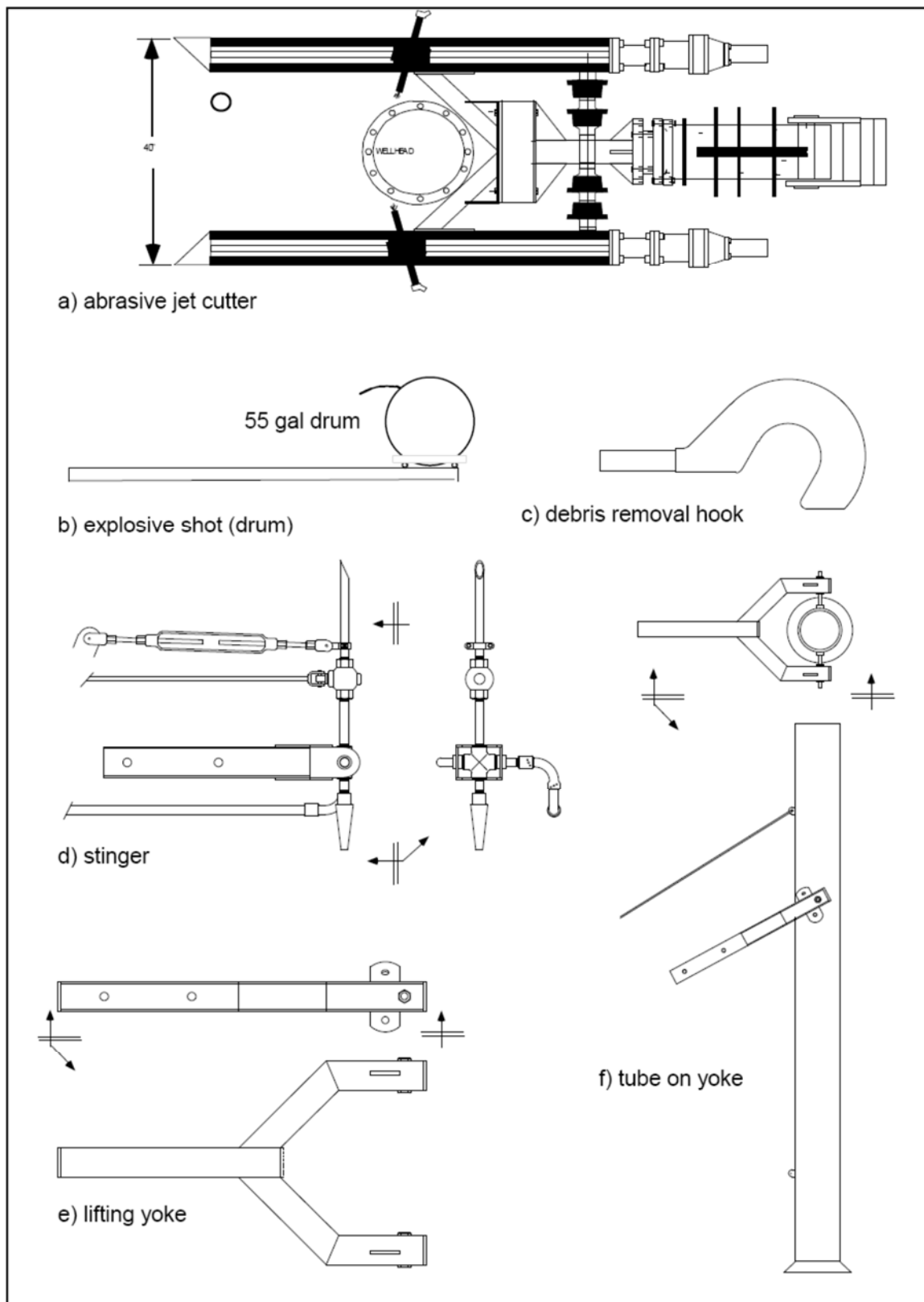


Figure F.3 Typical ACV End Attachments

10.6.2 Wellhead and BOP Removal

With the fire either extinguished or directed through a Venturi tube, close inspection of the wellhead equipment can be made and work can be performed at the wellhead. The inspection will determine whether the existing equipment can be used to attach capping devices or if all or part of it will need to be removed.

Caution! Reusing wellhead components that have been involved in a blowout can be hazardous and must be thoroughly evaluated. If nothing can be salvaged, the entire wellhead and all casing strings will need to be cut off and new equipment installed.

Wellhead or BOP components must be removed when they have suffered structural damage. Falling debris can cause mechanical damage and fire can weaken the integrity of most elastomer seals.

A typical technique for removing wellhead or BOP components is to install clamps on the flange to allow the removal of all bolts. A crane is attached to the component and snub lines are installed through the bolt holes. With the snub lines tight, the clamps are removed and the component can be taken off in a controlled manner. Other removal methods have included explosives, cables, and even hand-operated hacksaws. Some operators have resorted to tearing the wellhead off with brute force, which often caused additional damage and prolonged capping work to repair the casing.

Explosives have proved to be a highly precise and reliable method for removing wellhead equipment or sections of casing at the surface. This technology requires very specialized expertise and highly experienced personnel.

Shaped charges can be constructed to accomplish a variety of tasks, from severing the entire wellhead to removing casing valves or strings. If properly applied, shaped charges can remove an outer string of casing without damaging the next inner string. Figure F.4 shows a typical shaped charge configuration with a focused bias for removing a single outer casing string.

By contrast, the cable method is a crude type of friction cut. It is now considered outdated technology. Wire rope or cable is wrapped around the wellhead or casing and each end is connected to a swabbing unit. The cable is then dragged back and forth until it severs the casing. The cable method works, but often takes several days. Depending on the number of casing strings and the presence of cement, the job could take from two to five days of continuous cutting. There are other disadvantages to this method. The cut is difficult to re-enter if the cable is pulled out of the groove. Cable replacement is often necessary due to wear, overheating, breakage or when the operation is shut down for darkness. Cable cutting can cause the casing to become egged, further hindering the capping operation.

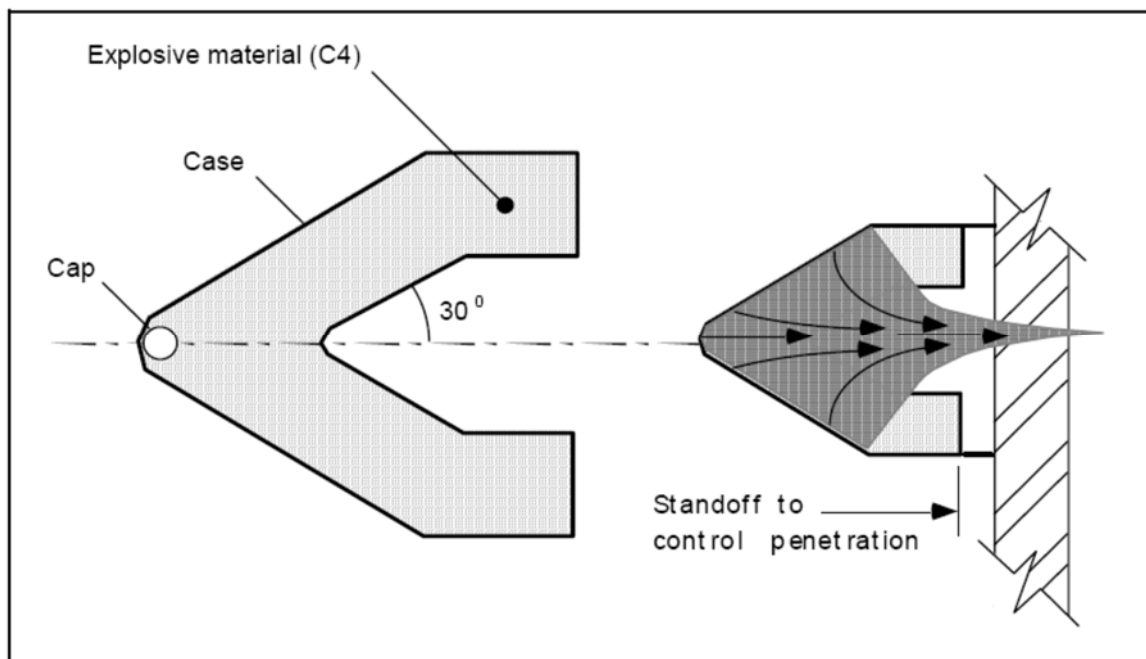


Figure F.4 Shaped Charge Diagram

The Kuwait oil fires proved the perfect testing ground for the abrasive jet cutter, a newer and more efficient cutting method. This equipment performed well in the removal of damaged wellhead components and trees. It was one of the most important innovations responsible for increasing the speed of capping operations in Kuwait. Two types of cutting services were used there: the Hydro-Jet (by Halliburton) and the Ultra-High-Pressure (UHP) abrasive particles to erode away metal and cement, but they are very different tools.

The UHP equipment is an ultra-high pressure, trailer mounted, self-contained system capable of quick mobilization and easy rig up. Rig-up consists of attaching a split-type track with hydraulic advancing tractor to the wellhead above or below the area to be cut off. This is typically done by two men without a crane. The tractor and nozzle are then positioned on the track and attached to the water, abrasive and hydraulic lines.

A high pressure, low volume stream of water and abrasive slurry is pumped through the jet at the area to be cut, and a circumferential cut is performed. The device works very much like an automatic track torch used to bevel pipe. The water leaves the jet nozzle with a pressure in excess of 30,000 psi. Generally, the nozzle used is a 0.75 mm diameter, man-made ruby. The calculated nozzle velocity at a typical pump rate of 4 gpm is 2,007 ft/sec (roughly equivalent to Mach 2⁺). The abrasive material is conveyed to the jet body through a separate line with compressed air. The abrasive enters the jet through a siphon port by Venturi effect and is discharged through the nozzle. Excess abrasive returns to the hopper through a hose. In Kuwait, the abrasive used was granulated garnet with a hardness of 7.5 as compared to steel at 6.0

The jet can be configured in different ways to meet specific cutting requirements. In several instances in Kuwait, it made circular cuts through as many as seven cemented strings of casing, with one or more blowing, to remove a damaged wellhead. The average time spent on this type of circular cut was between one and two hours with many done in less than one hour.

To cut off a wellhead completely, the jet nozzle is pointed directly at the casing, perpendicular to its axis. The jet circumnavigates the casing on the track, making a complete 360 degree cut. The jet stream usually penetrates 15 to 18 inches. Depth of penetration is highly dependent on the tracking speed.

Sometimes it is necessary to leave the inner string or production casing intact and peel back the outside strings. This is done by setting the jet at an angle where the abrasive stream never penetrates deeper than the thickness of the outer string. In either case, the cut is remotely controlled by the operator and no personnel are required close to the wellhead during the cutting operation.

The UHP jet cutter is not limited to circular casing cuts. For example, the track can be attached to the wellhead, allowing cuts to be made under damaged valves or between flanges. One unique application of the tool is for cutting bolts and other small diameter sections. In this case, the jet cutter is mounted on a tripod stand (see Figure F.5) and the operator can cut the nuts off the top or bottom of the flange in short order. The time required to cut a single API 11" 3M stud ranges from 45 seconds to 8 minutes. Sometimes the bolts can even be cut between the flanges, depending on the severity of the damage.

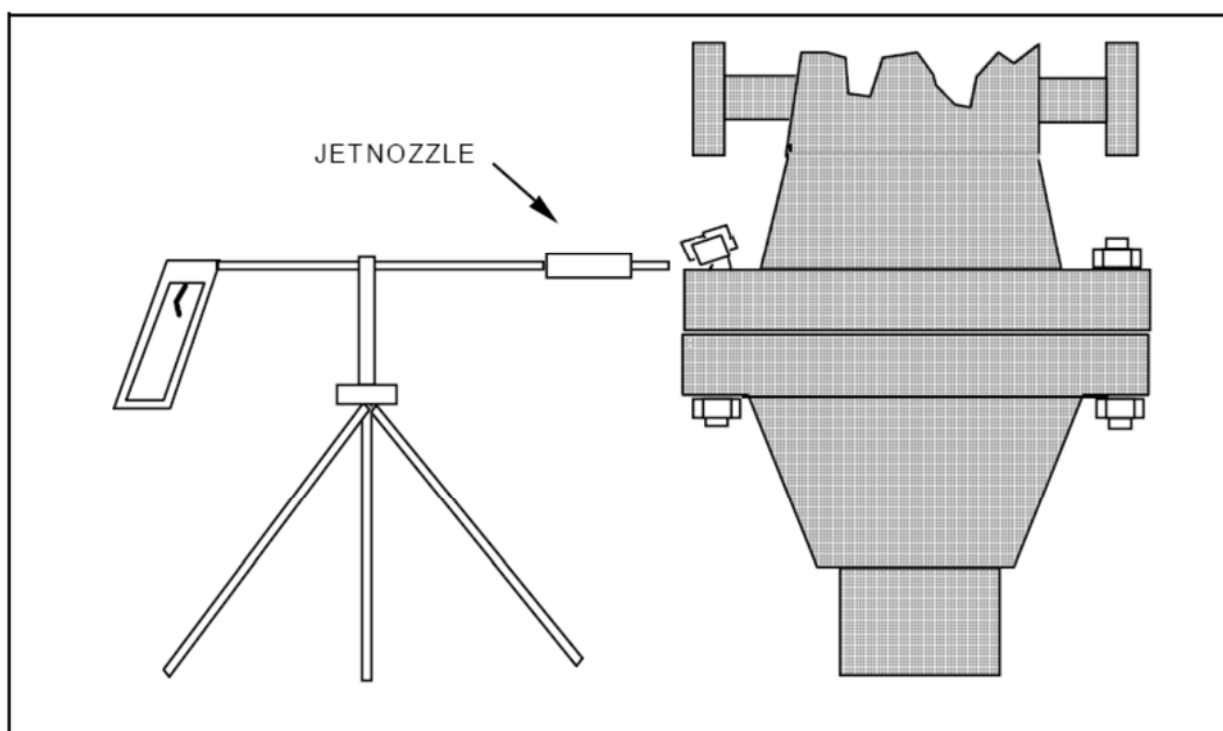
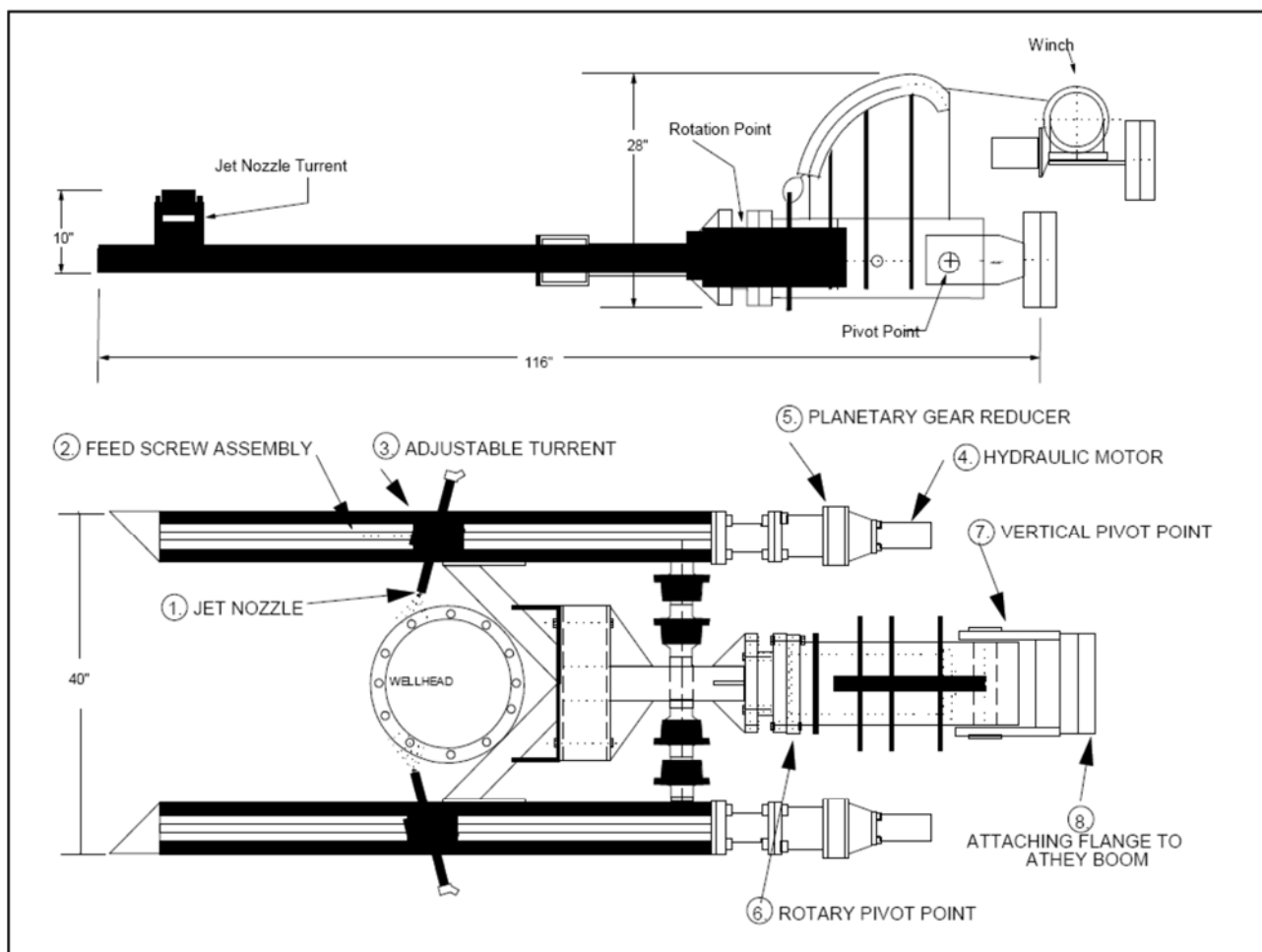


Figure F.5 Bolt Cutting with a Hand-Held Gun and Tripod

The ultra-high pressure cutting tool does have some limitations. The operator must physically attach the tractor band to the wellhead or casing, and when there is lateral flow this is virtually impossible to do. The cut is jagged and often irregular, perhaps because of the light construction of the tracking frame. But despite these minor limitations, the UHP jet cutter is a valuable asset to the capping operation.

Halliburton's HYDRA-JET cutter was adapted for use in Kuwait by the creation of a specialized carrier, allowing it to be conveyed to the wellhead using a conventional ACV boom. Two different carriers were employed in Kuwait. One was a vertical cutter with a single nozzle. The other was a horizontal carrier with a U-shaped yoke and two opposing jet nozzles (see Figure F.6). In both versions, a small hydraulic motor drives long worm screws to advance the cutters along the length of the yoke. To make the cut, a slurry of gelled water and 1ppg sand is pumped at 150 gpm to each 3/16" nozzle, a much higher flow-rate than the UHP device, and at a lower pressure of approximately 11,000 psi. The abrasive stream of high pressure slurry erodes away the casing or wellhead, tracking laterally much like a hacksaw blade passing through a piece of pipe.

The jet cutter requires considerably more rig-up time and equipment than the UHP unit. However, the jet cutter can cut off a wellhead that is on fire or has limited access due to lateral flow, because it can be conveyed at the end of the ACV boom. It can be cooled and shielded from the fire by a water spray. Its hydraulic control lines are protected in an arrangement that resembles a tube-and-shell heat exchanger. The lines run inside the tube and water is circulated around them to cool the system.



Halliburton Horizontal Cutter With Yoke Attachment
(Courtesy of Halliburton Energy Services, Duncan OK)

Figure F.6 Halliburton Horizontal Cutter with Yoke Attachment

Table F.1 Comparison of High-Pressure (Hydro-Jet) and Ultra-High Pressure (UHP) Cutting Techniques

	Ultra-High-Pressure	Hydra-Jet Cutter
Pump Pressure	30,000 psi	10-12,000 psi
Discharge Rate	3 - 4 gpm	84 gpm – one nozzle 170 gpm – two nozzles
Nozzles	0.5 to 0.7 mm man-made ruby	3/16" tungsten carbide
Pump Unit	1 – single unit Self-contained	1 hydraulic hose/power unit 2 cement/frac trucks
Cutting Track	Circular ± 200 lbs	U-yoke and vertical types ± 1,800 lbs
Rig-Up	No crane required attaches by hand with screw clamps ±1 hr.	Crane and AVC boom required boom refit (if required) ± 6 hrs
Well Conditions	Fire extinguished personnel access required.	Well can be on fire no close personnel access required
Fire Protection	None available	Shielded and water cooled
Support Protection	50 bbls distilled water truck with filter	1 sand bulk truck 2 gelled water trucks
Feed Water	Drinking quality with tank	Semi-clean/brackish
Consumables	Crushed garnet	40 mesh frac sand, 1 ppg
Personnel	4	± 6

The vertical cutter has a single arm jet holder. It can be used to cut off wing valves or flowlines when necessary. The vertical cutting time of 50-80 minutes is comparable to the UHP, if rig-up time is not considered. In either vertical or horizontal position, the finished cut is clean and smooth.

Using the HYDRA-JET cutter does create some special logistical considerations. The higher cutting-fluid volume requires the use of tank trucks (or frac tanks offshore) to supply the fluid, and a bulk truck (or skid) to supply the sand. The high pressure, high volume fluid discharges also require more horsepower, resulting in a large equipment spread. On a small location extra dirt work may be required to accommodate all the equipment. The ACV boom must be retrofit to accommodate the carrier (unless special provisions are already built-in). The rig-up time of several hours should be taken into consideration for daylight-only operations. Based on the Kuwait experience, Halliburton has made substantial improvements to the jet cutter, reducing the amount of equipment required.

Even with their individual disadvantages, these tools far outperform previous methods for removing damaged components on blowing or burning wells. They represent a significant advance in wild well control technique.

Both cutters worked well in Kuwait and, between the two, almost any conceivable cutting job can be accomplished. It would be unfair to say that one was better than the other because both fit into useful niches. Table F.1 shows a comparison of the two cutters.

Following the cut-off, circumferential cuts must be made on the casing strings prior to capping. These cuts can be made with an abrasive jet cutter or a portable lathe die cutter. The lathe cutter utilizes a track, air or hydraulic motor and a hardened cutting blade similar to those used on commercial lathes. The lathe cutter can be split and wrapped around the casing so it can be mounted without entering the flow. The resulting cuts have beveled machine-quality edges. The casing strings are cut at different lengths to expose an adequate amount of the innermost string for capping purposes. If necessary, these cuts can be made with the well on fire.

10.6.3 Capping to a Flange

In large violent flows of high velocity, the snub-on technique is recommended for installation of a capping stack to an existing flange. This is not a hard and fast rule, but generally the idea is to control the movement of the capping stack along its three axes by the use of hoist, tag and snub lines. This method, illustrated in Figure F.7, involves the following steps:

- Rig up a capping assembly with a mating flange, and proper pressure, temperature and service ratings. Track weld the ring gasket to the bottom of the capping assembly flange.
- Hold a final safety and coordination meeting to insure that all personnel understand the safety procedures to be followed and the operational plans, including the contingency plan for a flash fire or explosion.
- Snub the capping assembly into the flow. Center and lower the capping assembly and mate the flanges.
- Install bolts and tighten to energize ring gasket seal.
- Connect hydraulic lines between the closing unit and capping assembly.
- Install diverter lines and kill lines as necessary, then continue with the chosen course of action, e.g., pump to kill, divert, or rig-up to snub.

Similar procedures are used whether the capping assembly consists of a valve arrangement or a BOP stack. Torque wrenches should be available to speed the installation and insure a proper seal since pressure testing is often impossible.

10.6.4 Capping to a Stub by Installing a Wellhead

This procedure is an option when the entire wellhead has been removed, leaving only a casing stub. After cutting back the outer strings of casing to expose the capping string, a standard slip-on weld type head is modified by adding pad eyes for attaching the snub lines. For ease of installation, this wellhead should be at least one size larger than the casing stub to be swallowed, for example, a 9-5/8" head would be used to cap 7" casing.

As an option, a plate can be tack welded onto the side of the head to deflect the flow and improve visibility as the spool is placed into the flow over the casing stub. This plate will have to be removed before installation of the casing clamps. Snatch blocks are secured to the base of the casing with a bolt-on clamp (see Figure F.8). Cables are threaded through the snatch blocks and attached to the head to facilitate the snub-on operation.

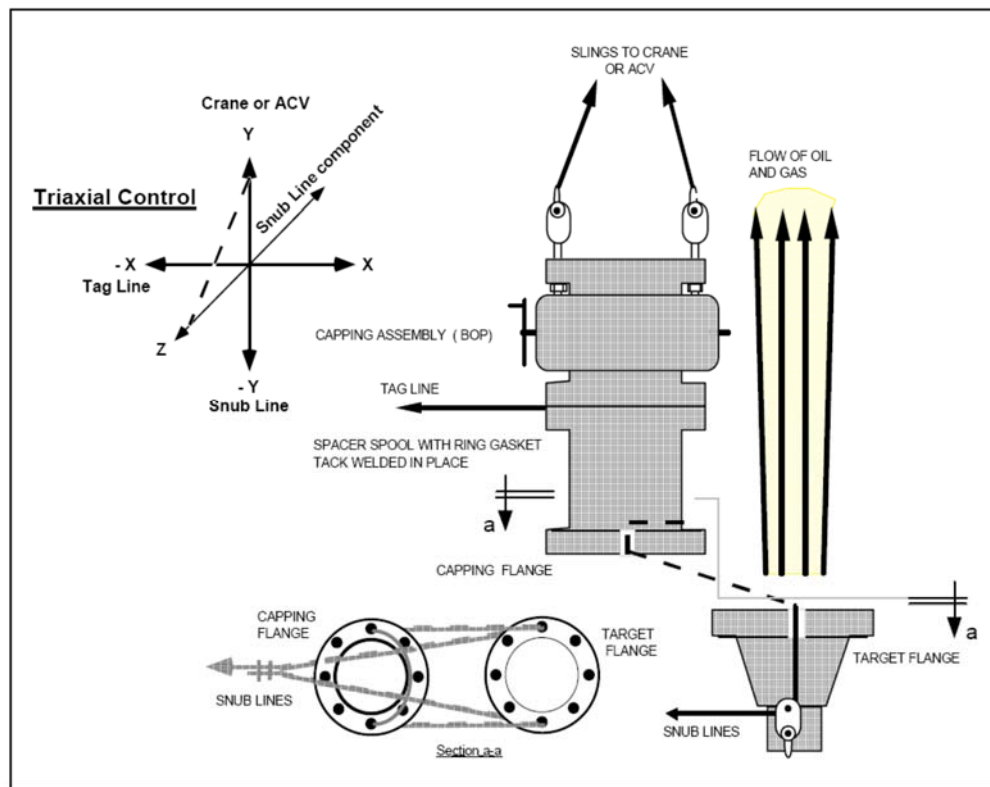


Figure F.7 Capping to a Flange via Snub lines

Once the head has been positioned over the casing stub, the blocks and snub line are removed. A second clamp is installed, but not tightened, between the existing clamp and the head. Hydraulic jacks are positioned between the two clamps (bottom clamp is secure, top clamp is loose). A standard set of split type casing slips are placed in the bowl and engaged by using the hydraulic jacks. After the slips are in place and the pack-off is energized, the top clamp is secured under the head to hold it in place when the hydraulic jacks are released. The sequence is illustrated in Figure F.9

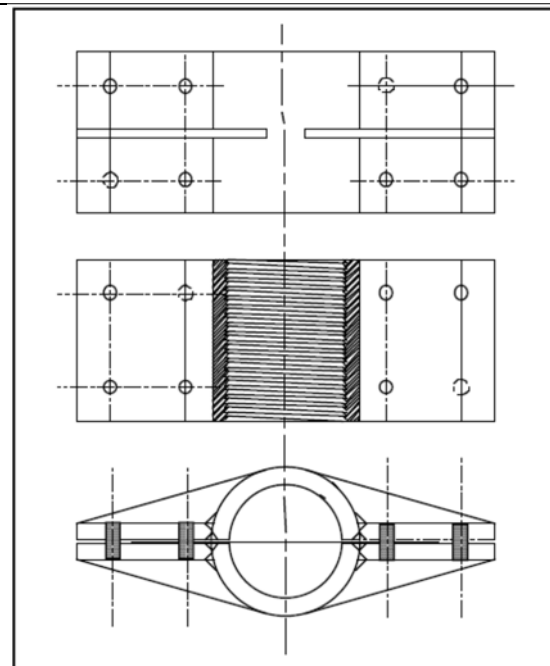


Figure F.8 Casing Clamp
(Courtesy of Blowout Tools, Inc., Lafayette, LA)

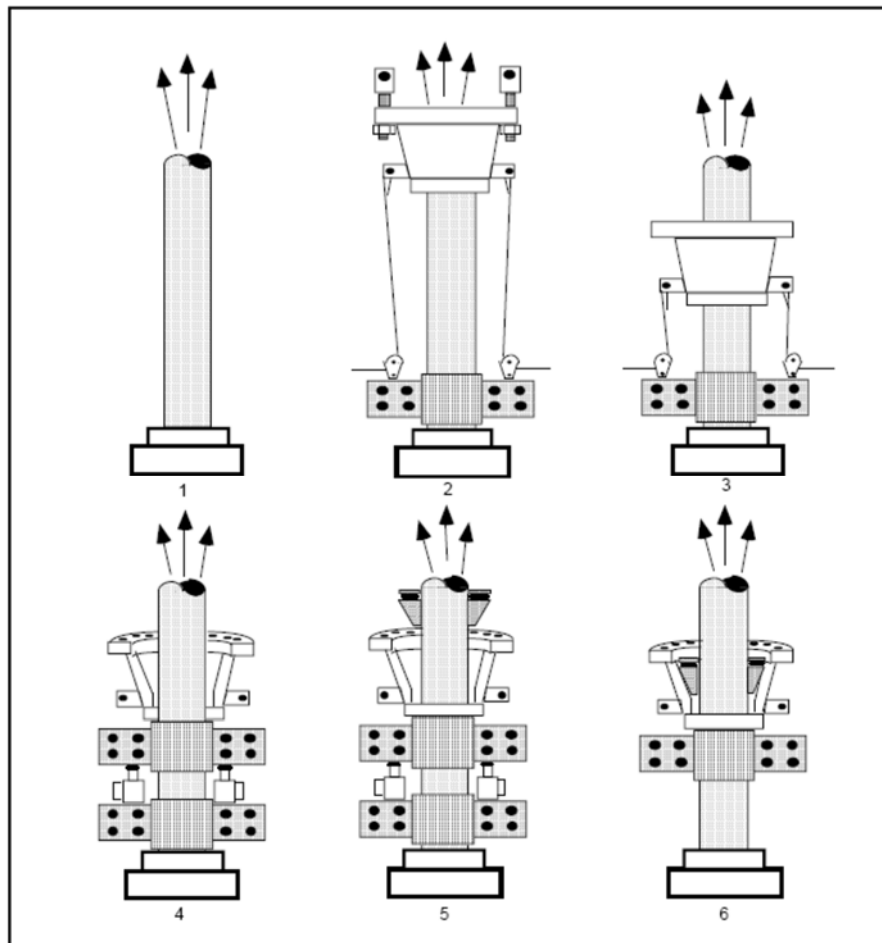


Figure F.9 Emergency Wellhead Installation

To calculate the jacking force required to fix the wellhead onto the casing stub, all subsequent operations should be considered, including.

- Rig deal loads (e.g. BOPE, snubbing equipment)
- Dynamic loading:
 - Pull from snubbing jack
 - Running casing
 - Applied pressure (e.g., shut-in bullheading)

A minimum of two calculations should be made based on the worst case scenarios for forces acting in the upward and downward directions, as illustrated in Example F.1

Example

Given:

SIWHP = 6500 psi

Casing Capped – 7-5/8" in., 47.1 lbs/ft, N-80 (0.8 F_y = 880 kbf, 80% Burst = 8,392 psi)

Snubbing jack weight – 22,000 lbs

BOPE Weight – 40,000 lbs

Snubbing String – 3-1/2" in. 15.5 lbs/ft S-135 DP (80% F_y = 464.8 kbf)

Measured Total Depth (MD) – 15,000 ft

Determine: a) Maximum upward & b) downward forces on wellhead (Fig F.10)

F_{ew}=Equipment dead weight (weight of snubbing jack, BOPs, etc.)

F_p=Pipe weight [ppf * pipe depth (ft)]

F_{p-a}=Pressure area effect (internal pressure* cross-sectional area casing I.D)

Worst Case – Upward Forces:

Bullheading at 80% burst pressure of casing with no pipe in hole.

$$\Sigma F = F_p + F_{ew} + F_t$$

$$F_p = 0$$

$$F_{ew} = 62,000 \text{ lbf}$$

$$F_{tw} = \frac{\pi}{4} (6.375^2) (8,392 \text{ psi}) \Rightarrow +267,865 \text{ lbf}$$

Therefore:

$$\Sigma F = F_p + F_{ew} + F_t$$

$$\Sigma F = 0 - 62,000 + 267,865$$

$$\Sigma F = 205,865 \text{ lb}_t \uparrow$$

Worst Case – Downward Forces:

Pipe on bottom (stuck) with wellhead pressure @ 0 psi. Pull 80% F_y of work string.

$$F_p = 0.8 F_y \text{ work string} = -464,800 \text{ lbf}$$

$$F_{ew} = 62,000 \text{ lbf}$$

$$F_t = 0 \text{ lbf}$$

Therefore:

$$\Sigma F = F_p + F_{ew} + F_t$$

$$\Sigma F = 464,800 - 62,000 + 0$$

$$\Sigma F = -526,800 \text{ lb}_f \downarrow$$

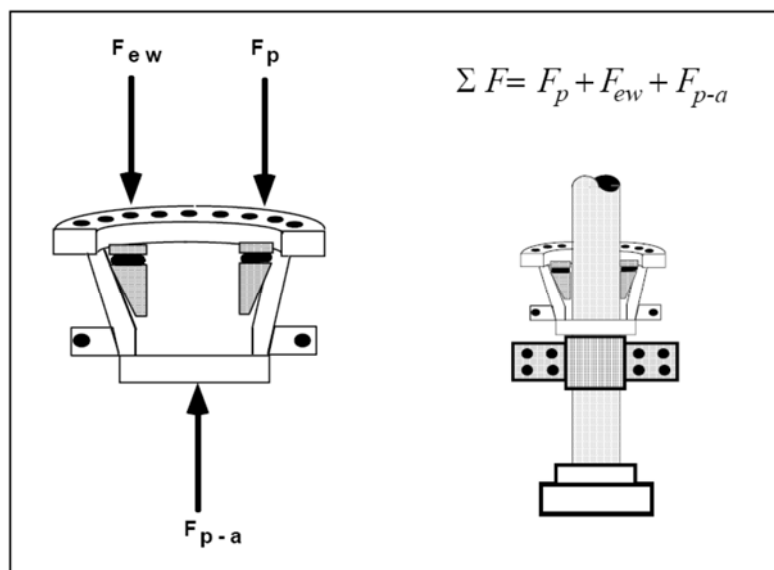


Figure F.10 Diagram of Wellhead Forces

Note that the net upward forces are transferred to the casing slips. These forces should not be allowed to exceed 80% of the casing tensile strength. Since the casing slips are incapable of imparting a downward force, all net downward forces are transferred to the casing via the casing clamp. Maximum unsupported bucking length associated with the worst case scenarios exceed 50% of the maximum tensile stress, bi-axial (axial and hoop stresses) calculations should be performed to evaluate the safety of the rig up.

10.6.5 Capping by Swallowing the Stub

Capping by swallowing the stub is an alternative when the entire wellhead has been removed. This procedure can also be used for capping drillpipe or tubing.

The typical capping assembly for this procedure (see Figure F.11) is a BOP stack. The stack is dressed out with (bottom to top):

- Slip rams
- Inverted pipe rams
- Drilling spool with one each manual and hydraulic valve on each outlet
- Blind rams

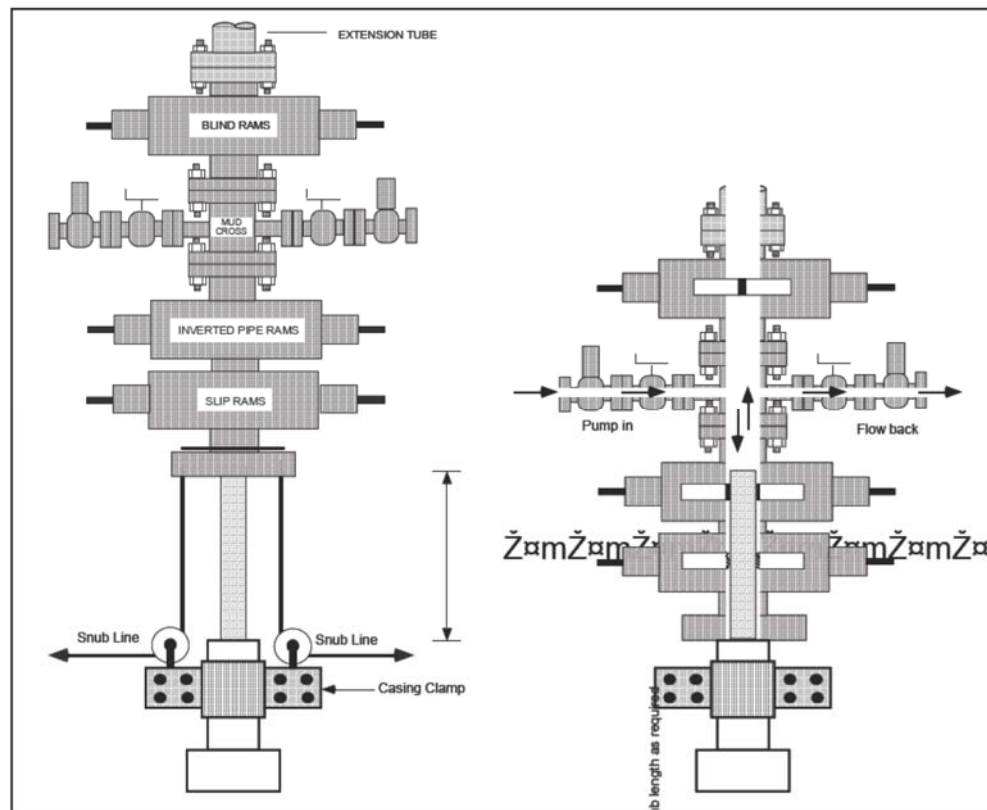


Figure F.11 Typical BOP Stack for Swallowing Casing Stub

Unlike pipe and blind rams, slip rams are not pressure sealing devices. They provide a mechanical grip only which is used to fix the BOP to the casing stub. Figure F.12 shows a diagram of a slip ram insert for a Cameron Type U preventer.

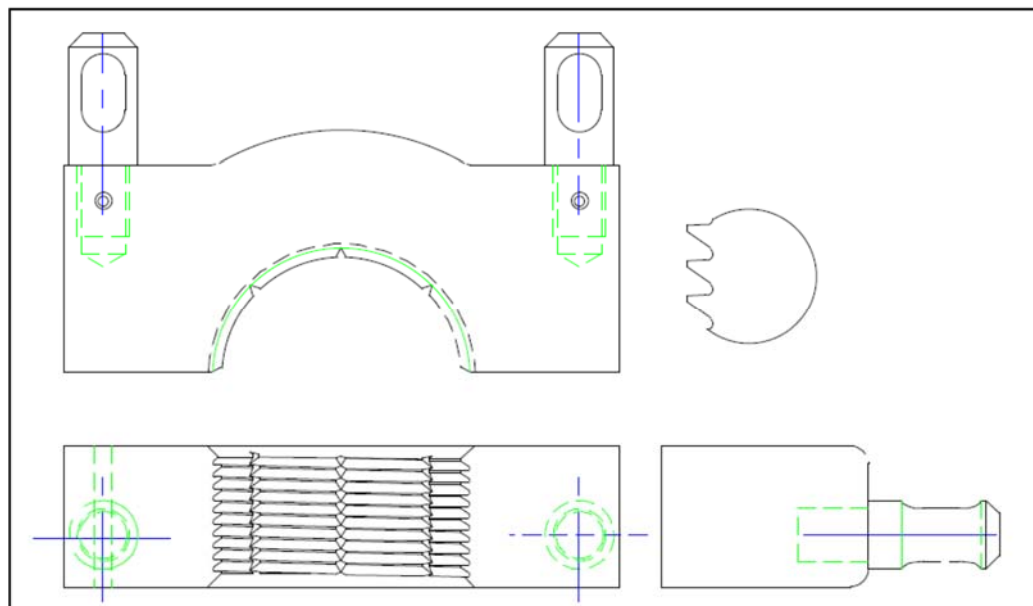


Figure F.12 Slip Ram Inserts (Courtesy of Blowout Tools, Inc. Lafayette, LA)

Once the proper amount of casing is exposed, a casing clamp is installed on the outer casing stub. This clamp is then used to connect the snatch blocks and the snub lines. The BOP stack is lifted with the crane and controlled with the snub and tag lines while being placed over the casing stub. With the BOP assembly safely over the casing stub, the hydraulic lines are connected from the closing unit. The rams are closed in the following sequence:

- Slip rams – to fix the BOP stack onto the casing stub. Note that the BOP must be laterally supported to prevent casing damage from bending forces.
- Inverted pipe rams – to contain the pressure exerted from the top.
- Blind rams – to shut-off the flow, or direct the flow through the side outlet valves for diverting.

The BOP stack can be stabilized with hydraulic jacks and casing clamps if further rig-up is required, such as snubbing or coiled tubing equipment.

10.6.6 Spin On Technique

Spinning a valve or BOP into a flow is a viable option for capping of a flow. The technique is illustrated in Fig F.13. The procedure is simple and has been in use since the 1930's. Very large flows can be handled this way in a safe and efficient manner.

One feature is that this can be done and requires no special materials or fabrication. Valves and BOPs can be removed as well as installed using this method. As in any capping operation the potential for ignition cannot be eliminated, so firewater protection for the capping crews must be maintained during this and all capping manoeuvres. One drawback is the close proximity of the capping crew to the flow. This aspect must be carefully evaluated. The procedures for installation to an existing flange are as follows:

- Install a hinge bolt (one longer bolt flange).
- Install a lever arm to the capping assembly and sling the assembly for lifting.
- Lift and position the capping assembly onto the hinge bolt at 180 degrees (see 'a-a' of Figure B.13)
- Position crane hook at centerline of the flow/flange to be capped.
- Cover the work area with fire water.
- Manually spin the valve into the flow and align capping and mating flanges.
- Drop in bolts and torque up to effect seal.

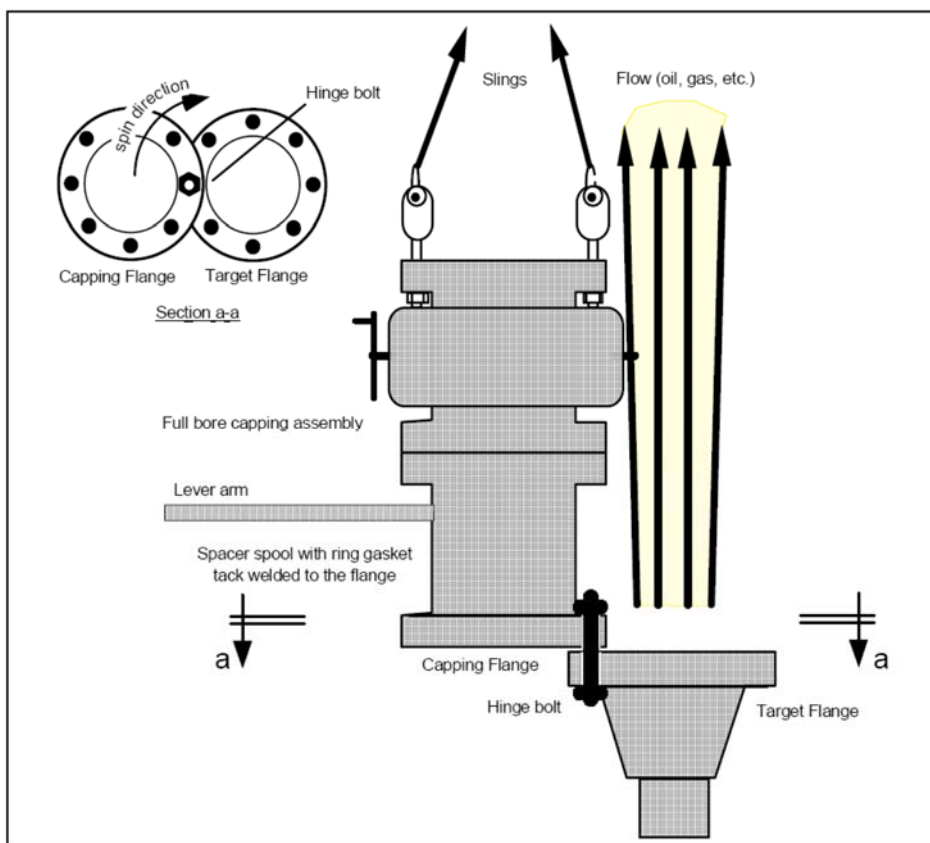


Figure F.13 Spin-on Technique

10.6.7 Forces Encountered during capping operations

The forces imparted on the capping assembly as it is brought into the flow stream can be substantial. A conservative approach is usually taken with regard to the size cables used for the snub lines. However it is sometimes useful to estimate the magnitude of the forces to be encountered. This is done by calculating the momentum flux through a control volume surface which is taken to be the area of the flow stream. This provides a conservative margin since only part of the flow should actually impact onto the capping assembly.

Equation

$$F_{mg} = \frac{S Q_g^2}{1.715 (10^{10}) Z D_c^2}$$

Where:

F_{mg} = momentum force of gas, lb force

S = gas specific gravity (Air = 1.0, natural gas use 0.6 to 0.7)

Q_g = volume rate of gas flow, scf/day

Z = average gas compressibility factor

D_c = diameter of flow (casing ID), inches

Equation F.2

$$F_{ml} = \frac{\rho Q_l^2}{2.6785 D_c^2}$$

Where:

F_{ml} = momentum force of the liquid, lbs force

ρ = fluid density, lbm/gal

Q = liquid flow rate, bbl/min

D_c = diameter of flow (casing ID), inches

Example

Given :

A gas flow rate = 50,000,000 scf/day (used to yield conservative result).

Casing size = 5-1/2 – in. O.D., 5.0-in. I.D.

Gas specific gravity = 0.7

Z factor = 0.95

Associated liquid of 28,000 bbls/day of 9.3 ppg salt water

$$F_{ng} = \frac{(0.7)(50,000,000)^2}{1.715(10^{10})(0.95)(5^2)} \Rightarrow 4296.5 \text{ lbf}$$

Second, calculate liquid momentum:

$$F_{ml} = \frac{(9.3)\left(\frac{28000}{24 * 60}\right)^2}{2.6785(5)^2} \Rightarrow 52.5 \text{ lbf}$$

The total force possible will be $4296.6 + 52.5 = 4349$ lbf or say 4500 lbf. Therefore the cables or boom must be able to withstand a live load force of about 4500 lbf. If a cable system is to be used a minimum safety factor of 4 should be used (4.0 is the preferred design safety factor recommended for this very critical component). Thus the design load will be 4×4500 or 18,000 lbs force.

10.6.8 Capping on Fire

Emphasis on environment and personnel safety has caused certain wells to be capped on fire. From an environmental viewpoint, leaving a well on fire can reduce the amount of pollution, provided the well is burning clean. One must realize that capping operations may take longer to complete if the well is left on fire throughout the entire operation. If the well is not burning cleanly then a judgment is needed to determine if less pollution will be caused if the fire is extinguished and thereby allow quicker capping operations.

Capping on fire is also justified if toxic gases are being produced, such as H_2S . Leaving the well on fire may be the solution to personnel hazards for the escaping gases. Regardless of whether the well is on fire or not, the work should proceed carefully taking necessary precautions for H_2S hazards while taking care to guard the intervention team from burns.

An ACV can be used to cap a well on fire. In this particular instance the main reason to leave the well on fire was to prevent pollution from running off into a creek. This creek fed directly into a

drinking water supply reservoir. For this reason it was imperative to avoid polluting the creek at all possible costs.

10.6.9 Stinging to Kill

The stinging operation is technique that can be used to kill a blowing well while it is on fire or simply blowing, provided certain well conditions prevail. Stinging to kill the well is the placement of a “stinger” in the throat of a blowing well in such a way that it functions as a temporary valve. The stinger has a hollow bore that will enable a kill fluid to be pumped into the well by bullheading. It may be the most expedient means to control the well provided wellhead and downhole conditions are favorable. In offshore operations, extra fabrication is sometimes necessary. Some means of placing the stinger at the wellhead will have to be fabricated based on the conditions of the well and structure. The conditions necessary for a successful stinging operations are:

- Shut-in wellhead pressure will be less than 1000 psi.
- Cross sectional flow area must also be fairly small (max 6.5” I.D.)
- There is an unobstructed access to the flow area.
- Ovality of the flow area must be less than 5%
- Downhole conditions are conducive for a bullhead kill.
- Pressure area effect must be less than 30,000 lbs force.

IF the SIWHP is greater than 1000 psi it may be difficulty to create a seal with bridging agents. Common bridging agents are hard rubber, gel, barite, nylon rope or other lost circulation material. These are mixed as a slurry and pumped ahead in a pill. They should be graded in size from 2 mm up to 20 mm (1/16” to 3/4”). Strips of rubber from tire inner tubes are an excellent bridging agent for stinging operations, however almost any type of lost circulation material will suffice. If the shut in pressure will produce more than 16 metric tons (35,200 lbs) of upward thrust from the pressure area effect, it may not be possible to provide rigging or tie downs that will prevent pump-out (ejection) of the stinger (which is assumed to be 99% round) is less than 5 mm (3/16 inch). If this gap is small the bridging agents can seal the leak, per the diagram shown in Figure F.14.

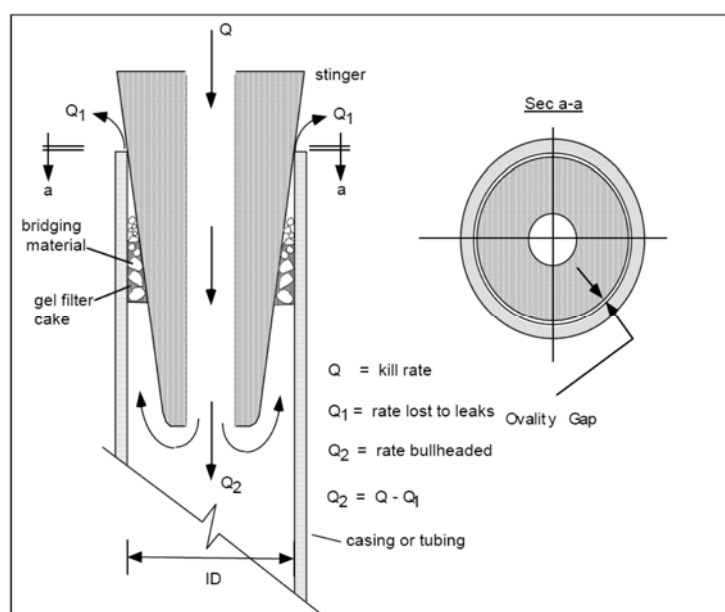


Figure F.14 Stinger Diagram

**Example
Given:**

A flow from 7" (6.24 inch I.D.) to be stung

Determine:

The maximum wellhead pressure to limit pressure area effect to 30,000 lbs force.

$$\begin{aligned} 30000 &= (\pi) \frac{(6.25)^2}{4} * WHP \\ WHP &= \left(\frac{30000}{30.67} \right) \\ WHP &= 977.8 \text{ psi} \end{aligned}$$

Downhole conditions must be conducive for a bullhead kill for the stinging operation. Although a pump and bleed (volumetric kill) procedure will in theory be possible, the general idea is to sting in, pump the bridging agents to seal the leaks and then bullhead the well dead.

Once the well is killed, the objective will be to secure the well. The stinger and its bridging agent seal cannot in any way be considered a permanent barrier. There are several options available. Install a:

- Slip-on weld type head (if productive string is weldable material).
- Temporary wellhead or
- Capping assembly (swallow stub) and/or permanent wellhead and re-tension casing strings.

10.6.10 Conclusions

In recent years there have been great advances in the techniques for capping and controlling blowouts. Equipment and techniques continue to improve due to cooperative efforts by both the capping vendors and the oil operators. This chapter has spoken to a few of the principles of the capping operation. There are many topics concerning capping that were not discussed here. We caution the reader that capping is an "experience-intensive" activity and absolutely nothing can replace the sound judgment that has been gained from years of doing the job. Although procedures have been offered, they are in no way complete. They have not been given for the purpose of guiding the inexperienced to become a capping crew, but for general information to aid all concerned with these types of operations.

Capping operations depend greatly on the situation. However, the three major types of capping operations – capping to a flange, capping by installing a wellhead and capping to a casing stub - cover a vast majority of all well control jobs. Although typically regarded as a somewhat "unscientific" undertaking, certain calculations can and should be made to insure that the end result will allow the subsequent operations to proceed safely.

Advances in explosive and abrasive cutting technology have resulted in improved methods for removing damaged equipment and preparing wellheads for capping operations. This technology should be used to its fullest extent to maximize the safety and efficiency of the capping job.

Stinging operations are applicable where certain conditions prevail. Where the circumstances will allow the use of the stinger technique, it should be considered, since it is a safe and effective means to control a blowing well.

10.7 RELIEF WELL INTERVENTIONS

Implementation of a relief well as a well control technique basically involves establishing direct communication with the problem well by directional drilling of a hole to a specific down hole location in very close proximity to the problem well and at a depth sufficient that will allow overcoming the blowout flow. The interception of the wellbore should be adequate enough to communicate with the blowout flow of the problem well. This would be considered a direct interception allowing a more effective control of the blowout flow. Alternatively, the relief well can be designed to communicate to the blowing reservoir with intentions to alter the reservoir properties with a matrix flood using water or polymers. Regardless of the objective, the relief well must make a close pass or interception of the blowing well to be successful. If possible and as a precaution, the interception should be planned and positioned to intercept within the plane of the maximum principal stresses of the formation rock. This will improve the chances to effectively communicate with the blowing well via the matrix or an induced hydraulic fracture when a direct interception fails. When a proper communication is established, it should be possible to pump kill fluid at designed rates to kill the well.

10.7.1 Kill Well Techniques review

In attempting to classify kill techniques, it is convenient to consider those which can be implemented directly over the blowing well (direct kills), and those that require the drilling of one or several relief wells.

Blowout control methods include some 'pumping', whether directly through the top of the blowing well or at depth via a relief well. The four basic pumping techniques that blowout 'specialists' usually refer to are:

- Overbalance kill
- Dynamic kill
- Momentum kill
- Matrix kill or flood kill

The best practice, once it is obvious that a 'simple kill' of the hydrostatic nature for instance will be ineffectual, is to prepare and spud a relief well concurrently with eventual surface kill preparations. If the surface kill fails, much time will have been gained.

The situation of the blowout will dictate the objectives of the relief well. The reservoir data and geological model will determine the type of kill required and the number of relief wells to consider. Once this has been established, quantity estimates and the availability of the following can be made.

- personnel,
- equipment,
- supplies,
- services, and

When making these estimates, the tendency is to look only to the worst possible case. While this is advisable in a contingency plan, a moderate or most likely scenario should also be investigated. Having alternative plans other than the worst case event will help eliminate "overkill" and waste and allow the operator to move quickly in response to the emergency.

The further the surface location of the relief well is from drilled well, and the greater the depth to the intercept target, the greater the degree of precision required in directional control. The depth of the blowout has a major effect on how the well is killed. If relatively shallow (less than 3000 ft) it

will require a shallow kick-off depth which can complicate directional control. The softer clays encountered while trying to obtain the high build and drop rates and high drift angles necessary just add to the directional control problems. Later under reaming or hole opening operations are also more difficult in such soft and often unconsolidated formations.

As the point of intersection becomes deeper, drilling times increase. However, the longer drilling time will allow orderly planning and mobilization of special equipment, supplies, and kill personnel. On the other hand, the deeper horizons are typically at a higher pressure and, up to a point, more prolific. The special equipment must therefore be sized upwards to meet the higher pressure and volume requirements. The deeper horizons and added drilling depths impact negatively on navigation as the ellipse of uncertainty increases. It might require many passes and re-drills before the blowing well is cleanly intercepted.

The planned trajectory is merely a general guideline and not an absolute rule. The relief well is drilled in three major phases.

- Phase I: Drill directionally to a point in space that converges near the blowing well's casing or BHA, within range of wireline proximity logs.
- Phase II: Locate the relative position of the relief well to the blowing well using proximity logging techniques and sound judgment.
- Phase III: Converge with the blowout well at the desired interception point (or a very close pass by) to establish the necessary communication to kill the flow.

In reality, the plan for the well can only take the relief well to the start of Phase II. After the well is located using proximity techniques, the final trajectory design will take place.

10.7.2 Positioning the Relief Well

Positioning the relief well involves a number of objective and subjective considerations. Listed below are the general factors taken into account while positioning relief wells for a typical exploration well:

- Direction of the prevailing winds as defined by the regional wind roses.
- Direction and dispersion of oil by the offshore currents.
- Safety perimeter around the well surface location (350m ± 10m) based on minimum pollution levels at the surface location and heat radiation of a 120 mmscf/d gas fire.
- The blowout's targeted bottom hole location and position uncertainty.
- The subsurface location of other wellbores.
- The presence of sea bed obstacles or installations such as pipelines
- Minimizing the distance and time to drill the relief well.
- Natural offshore characteristics which influence directional control
- The desired approach angle and direction in converging to the target.
- Degree of confidence in achieving a trajectory to interception.
- The depth at which interception must occur.
- Range and ability of proximity tools to detect casing or BHA (60 meters for induction tools / 50 meters passive magnetic).
- Maintaining as simple as possible trajectory and minimum dogleg severity; upper acceptable dogleg for planning purposes has been 2.0 deg/100 ft [0.667 deg/10 meters].

The position of the relief well is always more critical in an offshore location. Consideration needs to be given to current and wave behavior in the vicinity of the PTTEP location. The prevalent wind direction also dictates the location of the relief well.

Some of the factors in positioning the well include local regulatory and environmental considerations, the influence of the underwriters, the state of the seas and winds (current speed, direction, velocity, frequency), water depth, mudline conditions (debris, pipelines, sediments, obstacles, other wells), and the situation at the blowout site (size of the plume, type of well effluent, fires, surface cratering, state of the BOPE). There does not appear to be any minimum distance, except as dictated by specific conditions. Other factors relate to the well to be drilled, such as where the original well will be intercepted and the intercept trajectory. A site selected without due consideration of all relevant factors can result in increased difficulty and cost in reaching the desired objective. The location of the relief well for each blowout should be chosen based on its own merits.

More importantly, the relief drilling site and the relief well trajectory must not be compromised by any existing platform, wells, or well paths. It is difficult to conceive of a more extreme situation than a blowout at or near a producing platform, where numerous wells converge to the platform. The nearby wells interfere with ranging techniques and enhance the ellipse of uncertainty. These conditions might suggest that the blowing well be intersected as deep and as far away from the congested area as possible, even though the ellipse of uncertainty is greater. The platform scenario becomes more complex when multiple wells are blowing out, requiring multiple simultaneous relief well drilling operations. Every effort must be given to avoid any mooring pattern from overlapping other mooring patterns.

The general factors listed establish the preferred relief well location for a typical exploration well. An S-shaped trajectory for the relief well will usually suffice. This is the absolute shortest drilling distance that meets the objectives of the relief well and the 350 meter exclusion zone criteria. It represents an aggressive drilling trajectory with directional control, but compared to a simple J-shape that will require multiple plug backs, it is considered to be the most direct and efficient of all the possibilities. For a typical exploration well, a single relief location that is a sufficient distance from the well, but close enough that an aggressive drilling program is possible, is usually recommended. However, each case is unique.

10.7.3 Relief Well Target

In considering the relief well target, there are two distinct possibilities in the blowing well. The first is that the drillstring is on bottom and the other that the drill string is out of the hole, or pulled up inside the casing shoe (as in the string hung off before shearing the drillpipe). It is essential that there be metal (casing or drill string) in the blowing well for all types of proximity logs to function. If the target interception point is an open hole interval, the drill string must be across the target zone. If this is not the case, the target will be the deepest casing shoe. If the drill string is on bottom, the target can be where the blowing well penetrates the flowing reservoir. However, for planning purposes, the last casing shoe set is a target that is known to exist and therefore the most advantageous target as the primary initial target in Phase II. Should a blowout occur, the directional plan can be altered for deeper horizon targets when conditions justify such a change.

The Phase II objective will be converge to the blowing well at the estimated location of the deepest casing shoe. The relief well must be between 50 to 60 meters of horizontal distance from the blowout wellbore, and be approximately lined up (within 7 to 10 degrees in combined inclination and azimuth) when the end of phase II is reached.

Phase II begins when calculations show that the relief well has come within 50 to 60 meters of horizontal distance to the blowing well. (Note that the proximity logs measure distance between the two wells in a plane perpendicular to the well to be ranged to, therefore high angle wells may need adjustment of these criteria. At the depth of interest, the trajectory of the target wells in this

plan is vertical (or near vertical). Thus, the horizontal distance of 50-60 meters is valid without adjustment for inclination.

The first proximity survey can be made at the 50 to 60 meter range. However, one should not expect to receive definitive information until the distance between wells is 15 to 30 meters, and the most reliable information becomes available in the 1 to 15 meter range. Course corrections should not be made unless data from the proximity logs is in the 10 to 20 meter range, and confidence in the data collected is high.

Phase III, drilling to interception, is the most critical stage of the relief well project. Once the blowing well trajectory is determined, a precise trajectory can be determined for an interception. Given that confidence in the ranging data is attained, Phase III can begin.

The intercept point where the relief well and the flowing well are designed to come together is most usually at the bottom of the flowing well. This is normally where the flowing zone is found, except when serious pressure reversals exist. It is also the place where the kill fluid, when placed in the flowing well, has the greatest influence due to its having access to the entire drilled wellbore. An off bottom kill would require a higher kill mud weight to achieve a similar hydrostatic kill pressure. The bottom kill uses the lowest possible kill mud weight. However, bottom kill is not always the best approach. Lessons learned from the past tell us that in high permeability reservoirs (8 darcies, Ixtoc 1, June 1979) a bottom kill will never work.

The ellipse of uncertainty increases with depth so that more passes might be required before the flowing well can be hit with certainty. The deeper the well, the longer the drilling time. Temperature also increases with depth, so mud treatment becomes more complex. Ranging surveys and logging services also require more sophisticated methods at elevated temperatures. These effects, individually and collectively, increase operational costs. However, if the blowout well has several zones flowing, it might be necessary to consider a bottom kill *and* an off bottom kill.

Once the well is intercepted, the task will be to communicate directly with the blowing well. This communication will most likely occur by a breakthrough from the relief well to the blowout well when the wellbores are within 0.2 to 1 meter apart. This will depend on the flowing bottom hole pressure of the blowing well and the formation rock mechanics. In this case, the communication link should establish itself very quickly. It should become physically quite large (5 to 20 mm) and offer little if any flow restriction.

Once communication has been established, the objective shifts to pumping a sufficient volume of kill fluid into the blowing well, at an adequate rate to overcome and kill the hydrocarbon flow from the producing interval. Once control is achieved during the initial kill operation, both wells need to remain stable until abandonment or workover operations can take place. In no case should the kill operation expose the well to additional risk of unmanageable problems brought on by a worsening control situation. Reasonable judgment and practices should be taken in pursuing the kill operation. The kill should not be irreversible, nor should it unduly eliminate reasonable kill alternatives if the initial attempts fail. An example of an irreversible operation would be attempting to kill the well with cement rather than drilling mud. The overall plan should take this philosophy into account.

There is a remote possibility that in spite of best efforts, the relief well will miss the blowing well and make a close pass, perhaps 1 to 2 meters away. If a direct communication is not possible, it may be necessary to plugback to intercept. Depending upon the distance between wellbores, an acid job in carbonate rock may be considered to establish communication. This will work best if the relief well bore is in the pressure draw-down of the deepest producing zone. If this is the case, the acid will travel naturally through the matrix of the producing zone and into the blowing wellbore. A worm hole path will be created and the net result will be the creation of a direct communication between the two wellbores. This option should be carefully studied before implementation as there are many acid treatment designs using gels, retarders and concentrations to consider. Direct communication established through interception is better than relying on an acid job to create a

worm hole. Fracturing the rock matrix should be avoided, but if fracturing is to be attempted, then rock stresses will dictate the direction of the fracture path. If the intercept is not in the plane of the maximum rock stresses then the fracture will never intercept the blowing wellbore. Other options are perforating or milling techniques, if communication is to a cased hole.

10.7.4 Casing Design and Seat Selection

The relief well casing design and seat selection must meet both the requirements of the kill operation and the normal regional drilling conditions. The ultimate objective of the relief well is to overcome and kill the flowing well. The conditions imposed by this objective are additional requirements beyond the normal casing design.

Casing strings should be designed against the following conditions:

Regulatory agencies may set the minimum-design conditions they expect to see in wells drilled in their jurisdiction, relating to whether or not the well must contain the full pressure at the surface, the safety factor for collapse, and so forth. Typically, they will dictate the maximum setting depth for the surface string to protect any ground water supplies.

These conditions could be pressures during kick operations such as shutting in the well, circulating out the kick, or the pressures that could build if the pipe is sheared.

However, additional factors might need to be taken into account as the direct result of the blowout. If too little casing is set, there is the real problem of loss of circulation or worse, or even stuck pipe if differential pressures become extreme. If too much casing is set, you can run out of hole as the resultant hole size becomes too small to handle the large kill flow rates required.

- What is the impact on well design by the reservoir?
- Will the casing be of sufficient capacity to allow the high volume pumping required for the kill operation?
- Will the casing design allow for a back-up string in the event an additional string is required?
- Are any shallow zones pressure charged? Is the reservoir expected to be depleted in the vicinity of the wellbore?

These unique conditions that occur in the relief well are not common to ordinary wells. In an underground blowout, for example, there can be charging of upper formations or depletion of deeper formations. This may significantly alter previously observed conditions and present new problems during the drilling process. Additional factors have been considered and evaluated in addressing the relief well design:

- Effects of well casing configuration on the friction and flow rates required during the kill operation.
- Implications of setting an additional casing string to combat downhole problems encountered during drilling, i.e. can the objective still be attained if a further reduction in hole size is required or additional strings set.
- Realistic possibility of individual zones being artificially pressured or depleted and there is information to support this position.

Besides the above, certain questions should be reviewed before spudding the relief well, to take advantage of the most current information:

- Has the target location changed significantly since the relief well plan was developed?

- Were there complications encountered in the original blowing well during the up hole sections which could threaten the success of the relief well? How will these be averted?
- Will the casing schedule have to be modified to meet the directional drilling objectives required to intercept the blowing well?
- Was there an unanticipated presence of a corrosive or toxic fluid such as CO₂ or H₂S requiring special consideration?

If the relief well is to be considered as a replacement well for the blowing well then future requirements for production and stimulation must also be taken into consideration in the overall design. These details have not been covered by this study because it is thought that stimulation or productive casing loads are not to be applied to a relief well casing string. In other words, the relief well is thought of as a sole purpose well and not a producing well. The casings as detailed for a typical developmental and exploration well have been reviewed, and are adequate for all relief well loadings and conditions. Open hole and casing loads imposed by the kill operation have also been considered.

10.7.5 Ellipsoid of Uncertainty

The primary objective is to intersect the blowing well at some predetermined subsurface point (in this case the top of the producing formation). It must be realized that various factors detract from the ability to reach that point with pin point accuracy. The influence of the various factors is frequently described as the "cone of uncertainty." Normal directional well targets are usually a two dimensional circle or rectangle in the horizontal projection. The relief well must view the producing well's trajectory in a three dimensional perspective. Consideration is given to possible inaccuracies in, or lack of, survey data. As a result, rather than having a specific point for the target for the relief well, it becomes in reality an ellipse which is commonly referred to as the "ellipsoid of uncertainty".

While some would argue that an ellipsoid applies only to outdated directional survey tools, such as the single shot or multi-shot (not the EMS), it is still considered a standard to think of wellbore uncertainty as an ellipsoidal shape. High accuracy tools, such as the North seeking gyro, have equal accuracy in azimuth as they do in inclination, and therefore the ellipsoid would truly be a sphere.

The factors which influence the relationship of uncertainty in a relief well situation can be summarized as:

- Accuracy of the survey on the surface location (2 meters).
- Type of directional survey equipment employed and their inherent inaccuracies.
- Ability to confirm the well trajectory using different methods of measurement.

The following criteria are a guideline for the preparation of this relief well contingency plan:

- Initial spotting of the rig on the relief well location must be accurate to within 5 meters of the desired position. Surveys must be recalculated through interactive measurements until the accuracy is within 2 meters by the time the kickoff point is reached.
- Three types of survey tools will be used, the MWD, EMS and a North Seeking Gyro. Although not a directional tool the proximity tools will influence the degree of uncertainty. The tools will be supplied by the local directional or surveying vendors.

- The use of the three types of survey equipment in both open and cased hole will serve to verify the accuracy and repeatability of the surveys. Proximity tools will determine the relative position of the wells to each other once the wellbores converge within the tool's range. Details on the survey program will be provided under the topic "Directional Control."

The reliability of a relief well plan depends not only on the ability to accurately measure the hole position, but also on the prescribed directional program. On paper, a wide variety of relief well trajectories are possible, but in practice only a few are practical. The selection of a relief well location and the planned trajectory go hand-in-hand. As discussed earlier, a great number of considerations are involved in the selection of the relief well location. The weighting of the various considerations relative to this plan has been biased by:

- Desire to minimize the necessary drilling time by picking a kickoff point as deep as possible and planning a trajectory which minimizes survey requirements, eliminates additional motor runs and doesn't automatically require plugback operations.
- Avoidance of difficult directional maneuvers or approaches to minimize the possibility for failure.
- Availability of reasonably accurate survey data on the blowout wells makes it sensible to plan a relief well trajectory with a fairly deep initial crossing point for wellbore location.

10.7.6 Directional Control and Surveying Requirements

Maintaining a high degree of accuracy in the relief well directional control is essential for success. A successful relief well can be assured if stringent directional control is maintained.

- The relief well intersect of a blowing well is contingent on the ability to accurately map the blowing well's path from the surface to the bottom of the hole.
- A consistent directional survey program is the key to this goal.
- Inconsistencies in the directional data should be backed up by additional surveys resolve the differences.

10.7.7 Surveying Requirements for the Relief Well

The relief well directional program will follow a trajectory from the selected surface location to a point in close proximity to the wellbore of the blowing well. At that point proximity tools will detect the casing in the target wellbore. Once the target wellbore is located, the existing blowout directional surveys are tied into the proximity tool's results to guide the relief well to interception.

Survey data obtained in the relief well should maintain a high degree of accuracy in order to reach the interception objective. The survey policy for a typical exploration well is adequate for the depth of the wells, considering the range of the proximity logs. Full-time use of MWDs should now commence. Run a North seeking gyro to confirm the location below the kickoff point in the relief well before running surface and protective casings. Use the same vendor's downhole survey tools as were used in the blowout well, in order to limit tool characteristic variables. Duplication of data accuracy between wells is best achieved if any variance in tool characteristics is minimized.

Avoid collision except at the point of interest. When the relief well comes into the vicinity of any wellbore, it may be necessary to run proximity tools to verify that a premature collision will not occur. Note that Phase II of the drilling of the relief well begins when the calculated distance between the wells is about 60 meters. Proximity logs are used to avoid an early collision. If a collision is eminent, course corrections may be required to guide the relief well safely past the wellbore to the intended target.

10.7.8 Converging to a Blowing Well

Provided the directional surveys for the blowing well are reasonably accurate, it should be possible for the relief well to drill directly to the vicinity of the deepest casing shoe or the BHA left in the blowing well. The convergence path of the relief well presented in this plan should have a combined difference in both azimuth and inclination of less than 10 degrees from that of the target well. If the target well is to achieve this path, the relative position of the relief well to target well must be established at considerable distance from the crossing point. The radius of uncertainty can create a situation where it is very unlikely that an interception could be achieved using directional techniques alone (e.g. drill to a point in space without ranging to the target).

In essence, the proximity tool reduces the ellipse of uncertainty. For relief well plans, there are two primary types of proximity tools. One derives its ability to detect an adjacent well through an induced electrical field, while the other measures the magnetic flux between the tool and the casing or bottomhole assembly in the target well. Regardless of the tool used, metal (iron for the passive tool) in the BHA or casing of the relief well is required for these tools to work. If there is cased wellbore nearby, the interpretation can be difficult. Both proximity tools have unique sets of strengths and weaknesses so use both to take advantage of each tool's strengths.

10.7.9 Induction Tool

The induction tool makes use of an induced electromagnetic process which effectively, allows detection of a well within 50 to 90 feet. The inductive electromagnetic process requires the tool to be run in open hole. If the emitting electrode cannot be placed in open hole, the range is reduced to about 30 to 40%. For best results with the electric process range, the induction tool should be run in at least 100 meters of open hole. Open hole logging can be a major drawback if hole conditions are not optimal. A method used to overcome this problem has been to run open-ended drill pipe to just above the depth near the point of investigation. The tool is then run inside the drillpipe and allowed to exit into the open hole.

10.7.10 Passive Magnetic Surveys

The passive magnetic tool has detected casing at 150 feet. This process isn't strongly influenced by being run inside a non-magnetic drill collar, and is the preferred method of making the survey. The ability to run inside the string saves valuable rig time by eliminating trips. Although used to detect pipe at a distance of 150 feet, the accuracy of the passive tool is generally better within a 40 to 60 foot range of the target wellbore.

10.7.11 Intercepting and Establishing Communication

Under the conditions presented by a typical exploration well, direct interception of the blowing well in the open hole, at or below the top of the producing interval, should be the primary objective. If the well is cased, the objective will be to pass near the top perforation. The ideal point for the relief well to intercept the target well is at the top of the main reservoir, where kill weight fluid will be injected directly into the flow at its source. It is possible that a direct intercept cannot be accomplished, but adequate communication can be established between the wells. Since the reservoir is limestone, the communication can be through the rock matrix. Acid may be used to remove mud damage and open up the permeability if required.

If the target well is not intercepted, and acid fails to open up a sufficient flow path, more drastic methods may be required to establish communication with the well. The options will vary depending on the individual situation, but may include such operations as fracturing between wells or perforating the formation with a tubing conveyed shaped charge, oriented toward the target wellbore. However this option is considered a remote possibility because the confidence for making a wellbore interception is very high.

Despite the means necessary to establish communication, all preparations to perform the kill operation must be in place before drilling the final segment of the relief well. If an intercept is attained, there will be no option but to immediately commence the kill operation.

10.8 RELIEF WELL PLANNING

The purpose of this Appendix is to provide a generalized guideline for drilling a relief well. Information that is common to relief well planning and implementation is contained in this section. This Appendix does not address fully site specific issues for any particular reservoir or field.

It is important to remember that every blowout has a unique set of circumstances from which the majority of the planning process is directed. However, the strategy applied here is acceptable since the primary purpose of this appendix is to familiarize local personnel with some of the special techniques and services associated with planning a HTHP relief well. If an actual emergency were to occur, this planning process would have already been established and would save valuable time in a real intervention situation.

10.8.1 General Commentary on Relief Wells

The primary purpose of drilling a relief well is to kill an uncontrolled flow from a blowing well that cannot be reliably controlled at the wellhead by capping operations. One such example is when the well has cratered and there is no access to the wellhead leaving the relief well as the only feasible alternative. Another case is deep water wells where an offset re-entry kill is not possible. However, if the wellhead is accessible, capping operations are successful in controlling the well more than 97% of the time (making relief wells low probability options). While relief wells have been responsible for controlling only a minor number of all blowouts, they are an important part of well control capabilities.

The relief well is a special type of directional well. It is drilled from a surface location in as close a proximity to the surface well as possible. Its purpose is to provide a conduit, down which a kill mud of adequate weight can be pumped in sufficient quantities to arrest the blowout. The kill procedures might include the momentum kill, the dynamic kill, or flooding the reservoir. In practice, the trajectory of the kill well is designed to intersect the blowing well just above and as close to the inflow zone as possible. Casing or drillpipe is then set as close to this point as possible, prior to any attempt to kill.

Uncontrolled flows fall into two general categories: underground and surface blowouts. Subsea blowouts where the exit point is to the seabed are also classified as surface blowouts. Regardless of the exit point of the flow, the relief well will have the objective of a very close pass by, or an intercept of, the wellbore of the blowing well if it is to be successful (see Figure A.1). This will be at depth sufficient to kill the flow by pumping a kill fluid from the relief well into the blowing well. The interception of the wellbore should also communicate to the blowing well and create a viable flow path for the kill fluid from the relief wellbore. Alternatively, the relief well can communicate to the blowing reservoir to perform a matrix flood of the reservoir to control the well.

The situation of the well dictates the objectives of the relief well. In the preplanning phase, it is necessary to make educated guesses based on several likely scenarios. Much information is needed to describe the reservoir, such as its pressure, permeability, porosity, reservoir limits, and most importantly, the reservoir deliverability. This information is then used to determine the type of kill most likely to achieve the desired objective, the number of relief wells likely to be required, an estimate of the personnel, equipment, supplies, and services needed, and a timetable for the event.

When making these estimates, the tendency is to look only to the worst possible case. While this is advisable in a contingency plan, a moderate or most likely scenario should also be investigated. Having alternative plans other than the worst case event will help eliminate "overkill" and allow the oil operator to move quickly in response to the emergency.

Several case histories offer valuable insights into contingency planning for relief wells. Beginning with a Texas panhandle event in 1982, there have been three major events where the operator planned complicated kill operations from relief wells. These blowouts were all 'engineered' as

large volume, massive horsepower kill operations. At the end of the day, the exotic and costly kill operations were not required and therefore only served to fulfil the perceived design requirement.

In a 1989 North Sea control operation, preparations were made for a high horsepower, large volume pump job designed for what was perceived to be a worst case scenario. About 9,600 HHP was rigged up and kept on a constant state of readiness for 6 months. Upon interception of the blowing borehole with the relief well, the fluid in the relief well U-tubed by gravity into the blowout well, killing in a few minutes, and none of the high pressure horsepower pumping spread was employed to kill the well. Pumping requirements were limited to keeping the relief well hole full, which was accomplished with a single cement pump unit carried on board as part of the basic rig components. These wells are examples of “overkill” in the pumping requirements and the failure of the designers to account for the drawdown of the blowing well. On the contrary, if the reservoir is very strong (little depletion) large pump pressure and horsepower kill operations will be required. Another source of overkill in a relief well plan is excessive use of safety factors. If the reservoir parameters, leakoff losses, kill requirements, frictional pressures and pumping output all have safety factors applied individually, the overall result will be massive pumping spreads and volumes.

In the USA, there were two deep, high pressure wells which blew out in 1982 and 1985. Both wells were controlled by relief wells. The plans again called for high pressure/volume pumping kill operations. In both cases the kill volumes and pressures necessary were much less than anticipated. In these cases, as in the previously described North Sea operation, fluid in the relief well U-tubed into the blowing well on interception without assist from applied HHP from the surface. This again made the kill operation merely “keeping the relief well hole full”. Minimal assistance from the surface pumping equipment rigged up specifically for the kill operation was required, and in the opinion of the author, not justified. All wells were controlled by keeping the relief well full, at average pumping rates of less than 10 bbls per minute, until about one hole volume U-tubed into the blowing well. Thereafter, the wells were under control and circulation established.

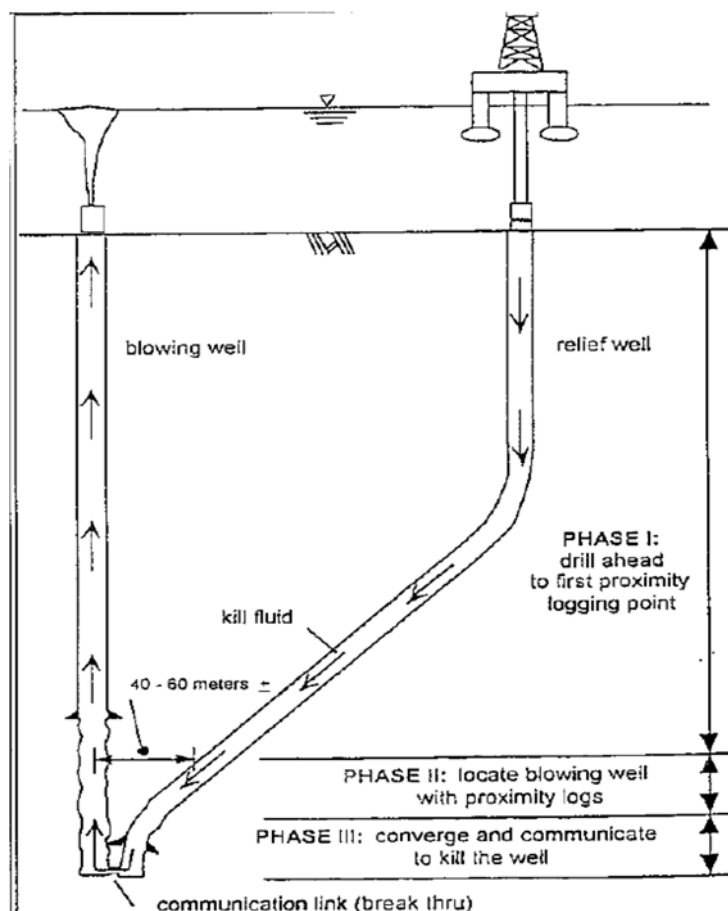
The point to be taken from these case histories is that there may well be a scenario where the blowout can be killed with conventional equipment, resources found in normal drilling operations, and may not require massive pumping spreads. However, there are situations in which a significant amount of hydraulic horsepower and kill volume is required. A concerted effort to offer both the worst case possible and a reasonable kill plan for a dynamic kill from a relief well is necessary.

10.8.2 General Trajectory and Objectives of the Relief Well

In simple terms, the relief well is a directional well that unlike the common directional well has a small, well defined target. Otherwise, the attributes are the same as a common directional well. The main objective will be to establish a direct communication with the blowing wellbore. This communication is the single most critical element in the success of the relief well. The accuracy of present technology for locating blowing wells with wireline proximity logs enables an interception or ‘hit’ of the blowing well to establish a direct communication link. The confidence for an interception is very high. In the last ten years, every relief well that has been drilled to objective with an interception in mind has been successful in achieving that goal.

To a large extent, the greater the depth of water the more the water will act as a buffer or choke to restrict the effluent flow. Gas will not escape as readily. Gases such as methane and hydrogen sulfide partially dissolve in the water, so their effects are lessened. Gases normally will not adversely affect operations where water depths exceed 1200 feet. The deeper the water, the less the reservoir drawdown, so kill pressures are higher. In some cases, reservoir conditions might cause localized depletion around the wellbore so kill pressures are lower. The further the surface location of the relief well is from drilled well, and the greater the depth to the intercept target, the greater the degree of precision required in directional control. For deeper water operations, the

offset well might be drilled in close proximity to the original well and track that well until close to the planned point of interception.



Relief Well Drilling Phases

The depth of the blowout has a major effect on how the well is killed. If relatively shallow (less than 3000 ft) it will require a shallow kick-off depth which can complicate directional control. The softer gumbo-type clays encountered while trying to obtain the high build and drop rates and high drift angles necessary just add to the directional control problems. Later under-reaming or hole-opening operations are also more difficult in such soft and often unconsolidated formations.

As the point of intersection becomes deeper, drilling times increase. On the one hand, the longer drilling time allows more orderly planning and mobilization of special equipment, supplies, and kills personnel. On the other hand, the deeper horizons are typically at a higher pressure and, up to a point, more prolific. The special equipment must therefore be sized upwards to meet the higher pressure and volume requirements. The deeper horizons and added drilling depths impact negatively on navigation as the ellipse of uncertainty increases. It might require several passes and re-drills before the blowing well is cleanly intercepted.

Besides establishing a communication link to the blowout well, the relief well hole must be maintained in such a state that the drillstring can be easily tripped in and out. The hole must be maintained for logging casing running and cementing operations, and most importantly, for well killing operations. Whenever possible, hole problems such as loss of circulation and sticking must be solved so that continuing progress can be made. If downhole drilling problems are not resolved, the well may not reach its objective. Progress cannot sacrifice these essential parameters. For example, the hole will be useless if proximity logs cannot be run without causing a fishing job.

The major differences between relief well and ordinary directional wells are that the target is much smaller and fluid injection rather than production will be the prime concern. In some cases, the target may be only inches wide, as in the Texas Panhandle well. Apache Key #1-11, where the objective was to hit a 5" liner at 16,080 feet (4902 m) TVD. In other cases, the target can be quite large as in matrix kill operations (Aramco Berri #34, 1979, where horizontal separation was approximately 40 feet). In this case the formation characteristics allowed the relief well to converge to a near passby of the target wellbore rather than an interception. Regardless of the type of kill operation desired, the ability to drill to a well-defined target will enhance the chance of success for the kill operation. Bearing in mind the small size of the target and the limited range (50-60 meters maximum) of the proximity tools, a relief well must be drilled with consideration for necessary course corrections.

The planned trajectory is merely a general guideline and not an absolute rule. The relief well is drilled in three major phases as illustrated in Figure H.1:

- Well's casing or BHA, within range of wireline proximity logs.
- Phase II: Locate the relative position of the relief well to the blowing well using proximity logging technique and sound judgment
- Phase III: Converge with the blowout well at the desired interception point (or a very close passby)

In reality, the plan for the well can only take the relief well to the start of Phase II. After the well is located using proximity techniques, the final trajectory design will take place.

10.8.3 Positioning the Relief Well

Positioning the relief well involves a number of objective and subjective considerations. Safety considerations are more straightforward and require prudent decisions. The trajectory required for interception strongly influences well placement, and involves more complex decisions based on the anticipated ability to achieve the prescribed directional drilling program. Listed below are the general factors taken into account while positioning relief wells:

- Direction of the prevailing winds as defined by the regional wind roses.
- Direction and dispersion of oil by the currents.
- Safety perimeter around the well surface location (as required) based on minimum pollution levels at the surface location and heat radiation.
- The blowout's targeted bottom hole location and position uncertainty.
- The proximity of other surface facilities or wells.
- The subsurface location of other wellbores.
- The presence of sea bed obstacles or installations such as pipelines.
- Minimizing the distance and time to drill the relief well/
- Natural regional characteristics which influence directional control.
- The desired approach angle and direction in converging to the target.
- Degree of confidence in achieving a trajectory to interception.
- The depth at which interception must occur.
- Range and ability of proximity tools to detect casing or BHA (60 meters for induction tools/ 50 meters passive magnetic).

- Maintaining as simple as possible trajectory and minimum dogleg severity; upper acceptable dogleg for planning purposes has been 2.0 deg/100 ft. [0.667 deg/10 meters].

The position of the relief well is most critical in an offshore location. Figure H.2 is excerpted from a Blowout Contingency Plan where factors listed above have been considered.

Most likely, the casing will be detected before a crossing occurs, and a mid-course correction made for an interception at the producing interval. However, if casing is not detected by the time that the deepest casing target point is reached, the relief well will drill ahead, holding angle and direction, until casing is located or total depth of approximately 20 meters above the reservoir is reached. If casing is still not located, the well must be plugged back and turned to a new target. Care must be taken to not penetrate the reservoir before protective casing is set. Once casing has been detected with proximity logs, the relief well will be turned and guided to make an interception at or near the reservoir penetration. The deepest casing point was chosen as the Phase II target because, unlike the drill string, it will always be in place. It is at sufficient distance up hole from the interception target that course corrections are possible to carry through an interception of the blowing wellbore.

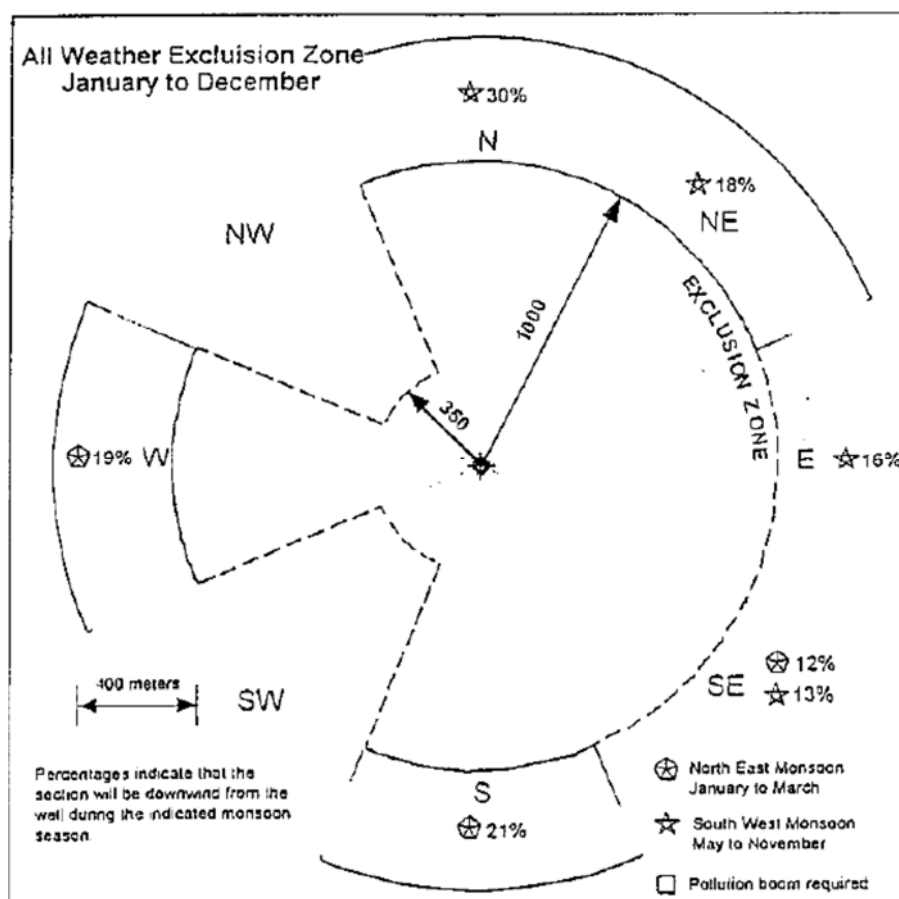


Figure H.2 Exclusion Zone Example for An Offshore Relief Well.

Phase I should be drilled in a manner similar to that of any other development well. The drill site for the relief well must be chosen with care. Particular attention must be paid to the surface location of the well, and to accurate directional control. The surface location must be accurate to within 5 meters when moving the rig onto the desired location. Thereafter, the surface location of both the blowout and the relief well should be resolved to within plus or minus 1 meter accuracy.

The relief well site will often be a compromise based on several conflicting or complimentary factors. Some factors will point to a specific direction and location while others will point to contrary directions or locations.

Some of the factors in positioning the well include local regulatory and environmental considerations, the influence of the underwriters, the state of the seas and winds (current speed, direction, velocity, frequency), water depth, mud-line conditions (debris, pipelines, sediments, obstacles, other wells), and the situation at the blowout site (size of the plume, type of well effluent, fires, surface cratering, state of the BOPE). There does not appear to be any minimum distance, except as dictated by specific conditions. For example, the intensity of the fire, if present, might require the relief well be situated a thousand feet or so away from the heat source. Other factors relate to the well to be drilled, such as where the original well will be intercepted and the intercept trajectory. A site selected without due consideration of all relevant factors can result in increased difficulty and cost in reaching the desired objective. A single site can rarely be optimally located to serve multiple blowouts. The location of the relief well for each blowout should be chosen based on its own merits.

More importantly, the relief drilling site and the relief well trajectory must not be compromised by any existing platform, wells, or well paths. It is difficult to conceive of a more extreme situation than a blowout at or near a producing platform, where numerous wells converge to the platform. The nearby wells interfere with ranging techniques and enhance the ellipse of uncertainty. These conditions might suggest that the blowing well be intersected as deep and as far away from the congested area as possible, even though the ellipse of uncertainty is greater. The platform scenario becomes more complex when multiple wells are blowing out, requiring multiple simultaneous relief well drilling operations. Every effort must be given to avoid any mooring pattern from overlapping other mooring patterns.

The general factors listed establish the preferred relief well location for a typical exploration well. An S-shaped trajectory for the relief well will usually suffice. This is the absolute shortest drilling distance that meets the objectives of the relief well and the 350 meter exclusion zone criteria. It represents an aggressive drilling trajectory with directional control, but compared to a simple J-shape that will require multiple plug backs, it is considered to be the most direct and efficient of all the possibilities. For a typical exploration well, a single relief location that is a sufficient distance from the well not to create a hazard for the drilling crew, but close enough that an aggressive drilling program is possible, is usually recommended. However, each case is unique.

10.8.4 Discussion of Relief Well Targets

In considering the relief well target, there are two distinct possibilities in the blowing well. The first is that the drillstring is on bottom and the other that the drill string is out of the hole, or pulled up inside the casing shoe (as in the string hung off before shearing the drillpipe). It is essential that there be metal (casing or drill string) in the blowing well for all types of proximity logs to function. If the target interception point is an open hole interval, the drill string must be across the target zone. If this is not the case, the target will be the deepest casing shoe. If the drill string is on bottom, the target can be where the blowing well penetrates the flowing reservoir. However, for planning purposes, the last casing shoe set is a target that is known to exist and therefore the most advantageous target as the primary initial target in Phase II. Should a blowout occur, the directional plan can be altered for deeper horizon targets when conditions justify such a change.

The Phase II objective will be to converge to the blowing well at the estimated location of the deepest casing shoe. The relief well must be between 50 to 60 meters of horizontal distance from the blowout wellbore, and be approximately lined up (within 7 to 10 degrees in combined inclination and azimuth) when the end of phase II is reached.

Phase II begins when calculations show that the relief well has come within 50 to 60 meters of horizontal distance to the blowing well. (Note that the proximity logs measure distance between the two wells in a plane perpendicular to the well to be ranged to, therefore high angle wells may need

adjustment of these criteria. At the depth of interest, the trajectory of the target wells in this plan is vertical (or near vertical). Thus, the horizontal distance of 50-60 meters is valid without adjustment for inclination.

The first proximity survey can be made at the 50 to 60 meter range. However, one should not expect to receive definitive information until the distance between wells is 15 to 30 meters, and the most reliable information becomes available in the 1 to 15 meter range. Course corrections should not be made unless data from the proximity logs is in the 10 to 20 meter range, and confidence in the data collected is high. Figure H.3 shows how the first proximity log run can be calculated. This is of course based on the survey accuracy of the tools used.

Phase III, drilling to interception, is the most critical stage of the relief well project. Once the blowing well trajectory is determined, a precise trajectory can be determined for an interception. Given that confidence in the ranging data is attained, Phase III can begin.

The intercept point where the relief well and the flowing well are designed to come together is most usually at the bottom of the flowing well. This is normally where the flowing zone is found, except when serious pressure reversals exist. It is also the place where the kill fluid, when placed in the flowing well, has the greatest influence due to its having an access to the entire drilled wellbore. An off-bottom kill would require a higher kill mud weight to achieve a similar hydrostatic kill pressure. The bottom kill uses the lowest possible kill mud weight.

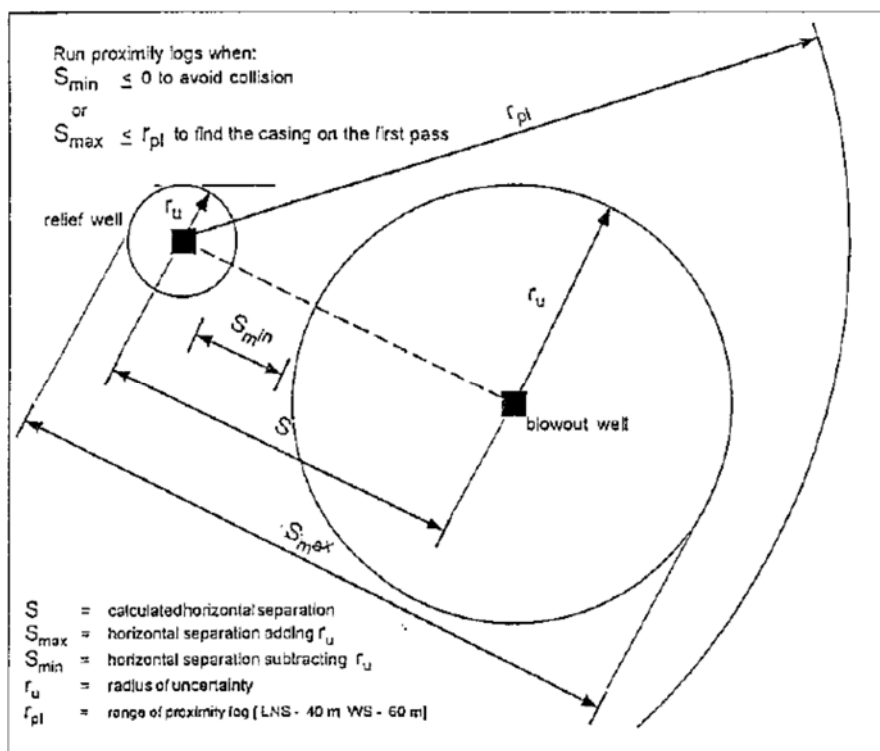


Figure H.3 Radius of Uncertainty Defined

The ellipse of uncertainty increases with depth so the more passes might be required before the flowing well can be hit with certainty, the deeper the well, the longer the drilling time. Temperature also increases with depth, so mud treatment becomes more complex. Ranging surveys and logging services also require more sophisticated methods at elevated temperatures. These effects, individually and collectively, increase operational costs. However, if the blowout well has several zones flowing, it might be necessary to consider a bottom kill and an off-bottom kill.

Once the well is intercepted, the task will be to communicate directly with the blowing well. This communication will most likely occur by a breakthrough from the relief well to the blowout well when the wellbores are within 0.2 to 1 meter apart. This will depend on the flowing bottom hole pressure of the blowing well and the formation rock mechanics. In this case, the communication link should establish itself very quickly. It should become physically quite large (5 to 20 mm) and offer little if any flow restriction.

Once communication has been established, the objective shifts to pumping a sufficient volume of kill fluid into the blowing well, at an adequate rate to overcome and kill the hydrocarbon flow from the producing interval. Once control is achieved during the initial kill operation, both wells need to remain stable until abandonment or workover operations can take place. In no case should the kill operation expose the well to additional risk of unmanageable problems brought on by a worsening control situation. Reasonable judgment and practices should be taken in pursuing the kill operation. The kill should not be irreversible, nor should it unduly eliminate reasonable kill alternatives if the initial attempts fail. An example of an irreversible operation would be attempting to kill the well with cement rather than drilling mud. The overall plan should take this philosophy into account.

There is a remote possibility that in spite of best efforts, the relief well will miss the blowing well and make a close pass, perhaps 1 to 2 meters away. If a direct communication is not possible, it may be necessary to plugback to intercept. Depending upon the distance between wellbores, an acid job may be considered to establish communication. This will work best if the relief well bore is in the pressure draw-down of the deepest producing zone. If this is the case, the acid will travel naturally through the matrix of the producing zone and into the blowing wellbore. A worm hole path will be created and the net result will be the creation of a direct communication between the two wellbores. This option should be carefully studied before implementation. Direct communication established through interception is better than relying on an acid job to create a worm hole. Fracturing the rock matrix should be avoided. Other options are perforating or milling techniques, if communication is to a cased hole.

In many old gas storage wells, the casing has become so corroded that conventional workover tools cannot enter the lower section of the hole. Techniques have been developed to mill a window from the outside of the casing from a relief well. The precision of this technique has allowed liners to be run into the lower section to tie it back to the original wellbore. If necessary, tubing-conveyed perforations can be used to make the communication. However, the authors are confident that milling can be used to cut a window in casing from the outside, if the blowout target is cased and a direct communication is needed.

10.8.5 HPHT or High Volume – Bottom Supported Operations

The following guide outlines the non-routine steps that would be considered in planning an actual high pressure high temperature (HPHT) relief well drilled in an offshore environment.

Define Objectives

The first step in this procedure is to establish the kill principle. Due to high pressures and temperatures, blowout flowrates, depths, reservoir characteristics, relief well casings and other factors the only practical method for controlling a HPHT blowout, that is not severely choked, is by direct intersection with the blowout wellbore followed by a dynamic injection of kill fluid.

Several hydraulic methods should be investigated, such as; dynamic kill with sea-water followed by mud, dynamic kill with brine followed by mud and mud as the only kill fluid. The method utilized would be dictated by the circumstances at the time of kill.

With this principle established, a primary objective will be to determine the relief well(s) placement, depth and proximity to the blowout to hydraulically regain its control. This information is required to arrive at a suitable well geometry.

Secondary objective is planning the hydraulic design. This information is necessary to design the casing program, to determine the number of required relief wells, and to specify the necessary surface and special equipment, rig requirements. Support vessels, etc.

Establish Kill Point

The kill point will usually be either at the last casing string set, along the drillstring or below the bit. The driving factors are; the bottom hole temperature at the reservoir, which will affect precision directional drilling and the kill rates required at the last casing shoe and the fracture gradients or potential weak zones affected by the kill.

Other elements to be considered are;

- Status of the blowout casing / wellhead
- Reservoir inflow performance and characteristics
- Blowout flow path and tubing performance
- Blowout fluid and kill fluid properties
- Formation drill ability
- Surface and special equipment required
- Risk analysis and probability of success.

Kill Program Design

Once the hydraulic kill principle, the kill depth, and proximity to the blowout wellbore is established, detailed planning can begin. The following steps are evaluated in this process;

Hydraulic Design

The hydraulic requirements for a kill on a HPHT well are complicated and require a two-phase time transient analysis to design the relief well casing, surface pumping plant, kill fluid volumes, final kill mud weight and pumping schedules to avoid fracturing the formation. Hydraulic planning process is an iterative process that may require several loops to arrive at an acceptable solution. The relief well kill simulations can be generated using “OLGA-Well-Kill”, a dynamic-multiphase-hydraulic computer simulator, maintained by Well Flow Dynamics a/s.

Surface Kill Equipment

The kill hydraulics for a HPHT blowout, depending on the circumstances, can be immense. This will require a significant kill pumping plant, large mud storage and mud transfer capacities, and

monitoring capability. Other special equipment will be a high pressure two-four outlet kill spool with a 10,000+ rating and long steel flexhoses to connect to the subsea wellhead if a floater is being used to drill the well. If possible a large jack-up would make the best relief well and killing platform for a HPHT blowout, assuming shallow gas charging is not a problem.

Casing Design

While conventional casing design criteria are employed when designing a HPHT relief well, several additional considerations must be investigated. The first is to design the kill string diameter to assure that the control fluids can be pumped at the required rate without excessive surface pressure. The second is to allow for at least one additional, emergency casing string to assure the required kill string diameter can be set. A third is to establish strength requirements for the casing strings that might be exposed to higher than normal burst and collapse forces during kill pumping, well control or complete loss of circulation. A fourth is environmental considerations, such as hydrogen embrittlement on high strength casing and connections, casing wear, high dogleg considerations for bending stresses, thermal loading and temperature effects during kill operation (e.g. cold fluid being pumped down a hot well at high rates will cause high thermal tensile stresses).

Rig % Surface Equipment

After the kill hydraulics and relief well casing program has been established, rig and surface equipment requirement can be investigated. This is again an iterative step, requiring an analysis of equipment and available rig specifications, their ability to achieve the initial design goals and then repeating the process until a successful outcome is expected.

Surface Equipment

- High and low pressure pumps
- High and low pressure manifolds
- Mud tanks and mixing equipment
- Water, mud and diesel supplies
- Mud supply vessels and transfer equipment
- Stimulation vessels

Rig(s) Selection

- Rig specifications
- Deck layout for kill equipment
- Special kill equipment
- Kill spools
- Long co-flexip hoses
- High pressure riser, etc.

Relative position uncertainty

One of the first steps in relief well geometry planning is to estimate the relative position uncertainty for the blowout and the proposed relief well(s). This is essential for determining the initial magnetic search depth, the number of relief wells required, and the angle of approach. Both the uncertainty in the surface positions and the borehole trajectory must be analysed.

Surface Uncertainty

More than one relief well has missed its intended target do to errors in, or misunderstanding, the surface coordinates and azimuth reference system of the two wells. To avoid this costly mistake, redundant surveys should be taken between the blowout and the relief well wellheads using different measuring techniques.

The main objective is to assure that no gross errors exist in the primary positioning system. The secondary objective is to fix the relative distance and true north bearing between the two surface locations to an uncertainty of +/- 1m, with a high degree of confidence.

For relief well drilling purposes only the relative position of the two wells is important (as opposed to UTM coordinates or Latitude/Longitude). Additionally, it is important to assure that a common azimuth and depth reference system is being used. This has caused many directional drilling problems in the past, particularly when switching between grid systems and magnetic / true north reference systems. Normally three independent measurements are sufficient to assure reasonable confidence in relative positioning, one using geodetic surveying techniques and sun-shots for true north reference if possible, to eliminate any grid errors.

Borehole Uncertainty

This step is essential in determining the initial magnetic search depth, the number of relief wells to start, and the angle of approach. This can be a complicated and confusing task. Reliance on position uncertainty models without analysis of the actual data is not adequate. The following items should be investigated by a borehole surveying specialist in conjunction with the service contractor supplying the instrument;

- Type of instrument
- Geographic location, borehole attitude
- Instrument uncertainty model
- Calibration data
- Field quality control
- Field data analysis
- Survey comparisons

Number of Relief Wells

Several factors must be considered when planning the number of relief wells to start. Technical and economic considerations are influenced by the required hydraulics to regain control of the blowout, high relative position uncertainty between the wells, and a high probability of encountering time delay problems during the course of the project.

These factors may technically require more than one well, or it may be an economic risk decision. That is, will the increased cost of a second well out-weight the risk of possible long delays or the complete loss of a single relief well?

Historically, the execution of two redundant, simultaneous and independent intervention projects has normally proven sufficient. If a surface intervention is undertaken, and has a reasonable chance of success, then a single relief well may be adequate. If serious pollution or other environmental damage is being caused by the blowout, two relief wells might be considered regardless of the surface intervention plans.

Initial Casing Search Depth

The items normally evaluated in establishing this point are;

- Type of search instrument

- Blowout tubular and sidetracked fish
- Formation characteristics
- Type of drilling fluid
- Relative position uncertainty
- Formation drill ability near detection point
- Well control considerations
- Well path and dogleg considerations

Relief Well Geometry

With the kill point, casing search and cross point, and surface location fixed, detailed directional planning can commence. The following items are normally considered in the relief well geometry.

- KOP, build, drop, and turn rates
- Formation consideration
- Well control/lost circulation
- Casing detection considerations
- Survey accuracy considerations
- Torque, drag, and casing wear
- Hole sizes and casing points
- Kill point approach angle.

Documentation and Audit Trail

If the blowout intervention operation develops into a major project with many people and organizations involved, both within and outside the company, control of critical documents can be very important.

This information will be required later by the insurance companies, regulatory bodies, upper management, and auditors, etc., not to mention future value as a training tool. It is even more important during the project to assure all well data is transferred properly, important operational steps are not omitted, engineering work is checked, written communication is properly distributed, confidential material is protected, and the meeting minutes are properly documented.

Under these circumstances, it is recommended to assign someone full-time to manage this task. This should be assigned to someone, preferably an engineer, who understands what is taking place, and should not arbitrarily be assigned to a secretary.

NON-STEERABLE DRILLING TOOLS

The drilling tools required to drill the relief well may vary somewhat depending on the exact requirements and availability at the time. Listed in Tables A.1, A.2 and A.3 are general listings to be used as a guide in preparation for drilling the relief well when using non-steerable systems (which may not be available in the region).

Table A.1: 17-1/2" Phase, Non-Steerable Directional Drilling Tools

Item	Qty	Size	Description	Connections (Up x Down)
1	2	9-5/8"	Down Hole Motor	7-5/8" Reg B x 7-5/8" Reg B
2	2	9-1/2"	Short Drill Collar (0.50m)	7-5/8" Reg B x 7-5/8" Reg P
3	1	9-1/2"	Short Drill Collar (0.90m)	7-5/8" Reg B x 7-5/8" Reg P
4	1	9-1/2"	Short Drill Collar (1.50m)	7-5/8" Reg B x 7-5/8" Reg P
5	1	9-1/2"	Short Drill Collar (2.0m)	7-5/8" Reg B x 7-5/8" Reg P
6	1	9-1/2"	Short Drill Collar (4.0m)	7-5/8" Reg B x 7-5/8" Reg P
7	1	9-1/2"	Short Drill Collar (6.0m)	7-5/8" Reg B x 7-5/8" Reg P
8	2	17-1/2"	Integral Blade Near Bit Stabilizer	7-5/8" Reg B x 7-5/8" Reg P
9	3	17-1/2"	Integral Blade String Stabilizer	7-5/8" Reg B x 7-5/8" Reg P
10	2	17-1/4"	Integral Blade String Stabilizer	7-5/8" Reg B x 7-5/8" Reg P
11	1	17"	Integral Blade String Stabilizer	7-5/8" Reg B x 7-5/8" Reg P
12	1	9-1/2"	Bent Sub – 2-1/2 degree	7-5/8" Reg B x 7-5/8" Reg P
13	1	9-1/2"	Bent Sub – 2-1/4 degree	7-5/8" Reg B x 7-5/8" Reg P
14	1	9-1/2"	Bent Sub – 2 degree	7-5/8" Reg B x 7-5/8" Reg P
15	1	9-1/2"	Bent Sub – 1-3/4 degree	7-5/8" Reg B x 7-5/8" Reg P
16	2	9-1/2"	Circulating Sub	7-5/8" Reg B x 7-5/8" Reg P
17	2	9-1/2"	Float Sub	7-5/8" Reg B x 7-5/8" Reg P
18	2	9-1/2"	MWD	7-5/8" Reg B x 7-5/8" Reg P
19	2	9-1/2"	UBHO Sub	7-5/8" Reg B x 7-5/8" Reg P
20	1	17"	Melon Stabilizer	7-5/8" Reg B x 7-5/8" Reg P
21	2	9-1/2"	Mandrel String Stabilizer	7-5/8" Reg P x 7-5/8" Reg P
22	5	Assort.	Sleeves	7-5/8" Reg B x 7-5/8" Reg P

Table A.2: 12-1/4" Phase, Non-Steerable Directional Drilling Tools

Item	Qty	Size	Description	Connections (Up x Down)
1	2	9-5/8"	Down Hole Motor	7-5/8" Reg B x 7-5/8" Reg B
2	2	9-5/8"	9-5/8" XO PDM	6-5/8" Reg B x 7-5/8" Reg P
3	1	8"	Down Hole Motor	6-5/8" Reg B x 6-5/8" Reg B
4	2	8"	Short Drill Collar (0.50m)	6-5/8" Reg B x 6-5/8" Reg P
5	1	8"	Short Drill Collar (0.90m)	6-5/8" Reg B x 7-5/8" Reg P
6	1	8"	Short Drill Collar (1.50m)	6-5/8" Reg B x 6-5/8" Reg P
7	1	8"	Short Drill Collar (2.0m)	6-5/8" Reg B x 7-5/8" Reg P
8	1	8"	Short Drill Collar (4.0m)	6-5/8" Reg B x 6-5/8" Reg P
9	1	8"	Short Drill Collar (6.0m)	6-5/8" Reg B x 7-5/8" Reg P
10	2	12-1/4"	Integral Blade Near Bit Stabilizer	6-5/8" Reg B x 6-5/8" Reg B
11	4	12-1/4"	Integral Blade String Stabilizer	6-5/8" Reg B x 7-5/8" Reg P
12	2	12"	Integral Blade String Stabilizer	6-5/8" Reg B x 6-5/8" Reg P
13	1	11-3/4"	Integral Blade String Stabilizer	6-5/8" Reg B x 7-5/8" Reg P
14	1	11-7/8"	Melon Stabilizer	6-5/8" Reg B x 6-5/8" Reg P
15	1	11-3/4"	Melon Stabilizer	6-5/8" Reg B x 7-5/8" Reg P
16	1	8"	Bent Sub – 2-1/2 degree	6-5/8" Reg B x 6-5/8" Reg P
17	1	8"	Bent Sub – 2 degree	6-5/8" Reg B x 7-5/8" Reg P
18	1	8"	Bent Sub – 1-3/4 degree	6-5/8" Reg B x 6-5/8" Reg P
19	1	8"	Bent Sub – 1-1/2 degree	6-5/8" Reg B x 7-5/8" Reg P
20	1	8"	Bent Sub – 1-1/4 degree	6-5/8" Reg B x 6-5/8" Reg P
21	2	8"	Circulating Sub	6-5/8" Reg B x 7-5/8" Reg P
22	2	8"	Float Sub	6-5/8" Reg B x 6-5/8" Reg P
23	2	8-1/8"	MWD	6-5/8" Reg B x 7-5/8" Reg P
24	2	8"	UBHO Sub	6-5/8" Reg B x 6-5/8" Reg P

Table A.3 : 8-1/2" Phase, Non-Steerable Directional Drilling Tools

Item	Qty	Size	Description	Connections (Up x Down)
1	2	6-1/2"	Down Hole Motor	4" IF B x 4" IF P
2	2	6-1/2"	Short Drill Collar (0.50m)	4" IF B x 4" IF P
3	1	6-1/2"	Short Drill Collar (0.90m)	4" IF B x 4" IF P
4	1	6-1/2"	Short Drill Collar (1.50m)	4" IF B x 4" IF P
5	1	6-1/2"	Short Drill Collar (2.0m)	4" IF B x 4" IF P
6	1	6-1/2"	Short Drill Collar (4.0m)	4" IF B x 4" IF P
7	1	6-1/2"	Short Drill Collar (6.0m)	4" IF B x 4" IF P
8	2	8-1/2"	Integral Blade Near Bit Stabilizer	4" IF B x 4-1/2" Reg B
9	4	8-1/2"	Integral Blade String Stabilizer	4" IF B x 4" IF P
10	1	8-1/4"	Integral Blade String Stabilizer	4" IF B x 4" IF P
11	1	8"	Integral Blade String Stabilizer	4" IF B x 4" IF P
12	1	6-1/2"	Bent Sub – 2-1/2 degree	4" IF B x 4" IF P
13	1	6-1/2"	Bent Sub – 2 degree	4" IF B x 4" IF P

14	1	6-1/2"	Bent Sub – 1-3/4 degree	4" IF B x 4" IF P
15	1	6-1/2"	Bent Sub – 1-1/2 degree	4" IF B x 4" IF P
16	2	6-1/2"	Circulating Sub	4" IF B x 4" IF P
17	2	6-1/2"	Float Sub	4" IF B x 4" IF P
18	2	6-1/2"	MWD	4" IF B x 4" IF P
19	2	6-1/2"	UBHO Sub	4" IF B x 4" IF P
20	1		Portable Computer	4" IF B x 4" IF P

10.8.6 Steerable Drilling Tools

The drilling tools required to drill the relief well may vary somewhat depending on the exact requirements and availability at the time. List in Tables A.4, A.5 and A.6 are general listings to be used as a guide in preparation for drilling the relief well when using steerable systems (which may not be available in the region).

Table A.4 : 17-1/2" Phase, Steerable System Tools, 5° – 6° /100'

Item	Qty	Size	Description	Connections (Up x Down)
1	2	9-5/8"	Steerable Motor, 0-3° Adjustable	7-5/8" Reg B x 7-5/8" Reg B
2	2	9-1/2"	Non-magnetic Drill Collars (10.0m)	7-5/8" Reg B x 7-5/8" Reg P
3	3	9-1/2"	Drill Collars (10.0m)	7-5/8" Reg B x 7-5/8" Reg P
4	2	9-1/2"	Short Non-magnetic Drill Collars (3.0m)	7-5/8" Reg B x 7-5/8" Reg P
5	2	17-1/2"	Integral Blade Near Bit Stabilizer	7-5/8" Reg B x 7-5/8" Reg B
6	4	17-1/4"	Integral Blade String Stabilizer	7-5/8" Reg B x 7-5/8" Reg P
7	1	17-1/4"	Integral Blade String Stabilizer	7-5/8" Reg B x 7-5/8" Reg P
8	1	17"	Monel Integral Blade String Stabilizer	7-5/8" Reg B x 7-5/8" Reg P
9	2	9-1/2"	Circulating Sub	7-5/8" Reg B x 7-5/8" Reg P
10	2	9-1/2"	Float Sub	7-5/8" Reg B x 7-5/8" Reg P
11	2	9-1/2"	MWD	7-5/8" Reg B x 7-5/8" Reg P
12	2	9-1/2"	UBHO Sub	7-5/8" Reg B x 7-5/8" Reg P
13	1	17"	Melon Stabilizer	7-5/8" Reg B x 7-5/8" Reg P
14	2	9-1/2"	Mandrel String Stabilizer	7-5/8" Reg P x 7-5/8" Reg P
15	5	Assort.	Sleeves	7-5/8" Reg B x 7-5/8" Reg P

Table A.5 : 12-1/4" Phase, Steerable System Tools, 11° – 12° /100'

Item	Qty	Size	Description	Connections (Up x Down)
1	2	9-5/8"	Steerable Motor, 0-3° Adjustable	7-5/8" Reg B x 7-5/8" Reg B
2	2	9-5/8"	9-5/8" XO PDM	6-5/8" Reg B x 7-5/8" Reg P
3	1	8"	Steerable Motor, 0-3° Adjustable	6-5/8" Reg B x 6-5/8" Reg B
4	2	8"	Non-magnetic Drill Collars (10.0m)	6-5/8" Reg B x 6-5/8" Reg P
5	2	8"	Non-magnetic Drill Collars (3.0m)	6-5/8" Reg B x 7-5/8" Reg P
6	3	8"	Drill Collars (10.0m)	6-5/8" Reg B x 6-5/8" Reg P
7	1	8"	Short Non-magnetic Drill Collars (3.0m)	6-5/8" Reg B x 7-5/8" Reg P
8	2	12-1/4"	Integral Blade Near Bit Stabilizer	6-5/8" Reg B x 6-5/8" Reg P
9	4	12-1/4"	Integral Blade String Stabilizer	6-5/8" Reg B x 7-5/8" Reg P
10	2	12"	Integral Blade String Stabilizer	6-5/8" Reg B x 6-5/8" Reg B
11	1	11-3/4"	Monel Integral Blade String Stabilizer	6-5/8" Reg B x 7-5/8" Reg P
12	1	11-7/8"	Melon Stabilizer	6-5/8" Reg B x 6-5/8" Reg P
13	1	11-3/4"	Melon Stabilizer	6-5/8" Reg B x 7-5/8" Reg P
14	2	8"	Circulating Sub	6-5/8" Reg B x 6-5/8" Reg P
15	2	8"	Float Sub	6-5/8" Reg B x 7-5/8" Reg P
16	2	8-1/8"	MWD	6-5/8" Reg B x 6-5/8" Reg P
17	2	8"	UBHO Sub	6-5/8" Reg B x 7-5/8" Reg P

Table A.6 : 8-1/2" Phase, Steerable System Tools

Item	Qty	Size	Description	Connections (Up x Down)
1	2	6-1/2"	Steerable Motor, 0-3° Adjustable	4" IF B x 4" IF B
2	2	6-1/2"	Non-magnetic Drill Collars (10.0m)	4" IF B x 4" IF P
3	3	6-1/2"	Drill Collars (10.0m)	4" IF B x 4" IF P
4	2	6-1/2"	Drill Collars (3.0m)	4" IF B x 4" IF P
5	1	6-1/2"	Short Non-magnetic Drill Collars (3.0m)	4" IF B x 4" IF P
6	2	8-1/2"	Integral Blade Near Bit Stabilizer	4" IF B x 4-1/2" Reg B
7	4	8-1/2"	Integral Blade String Stabilizer	4" IF B x 4" IF P
8	1	8"	Monel Integral Blade String Stabilizer	4" IF B x 4" IF P
9	2	6-1/2"	Circulating Sub	4" IF B x 4" IF P
10	3	6-1/2"	Float Sub	4" IF B x 4" IF P
11	2	6-1/2"	MWD	4" IF B x 4" IF P
12	2	6-1/2"	UBHO Sub	4" IF B x 4" IF P
13	1		Portable Computer	

10.8.7 Pumping Speeds

The worst horsepower case must be determined from the runs made with the dynamic two-phase flow simulator for a surface blowout flow, assuming that the design rate is 57.3 barrels per minute at 740 psi surface pumping pressure. The piping and discharge pressure specification for kill equipment shall be 5,000 psi. The 5000 psi rating is chosen because this is the minimum rating to be considered for any relief well pump job and secondly it is minimum rating commonly available

from pumping vendors. Horsepower is determined by rating of units rather than equating horsepower alone. The recommended method is per Equation A.1 shown below. Example A.1 shows that a minimum safety factor or 1.5 for pumping is recommended. Therefore, if a discharge of 750 psi is anticipated the required horsepower would be 8 units or 612 HP each for a total of 4896 HP (612 HP is the 100% rating for an HT-400 used in the example). If one were to use a simplified approach where HP is merely pump discharge pressure time rate the calculations would yield only a minimum of 1040 horsepower without SF and 1560 HP with a 1.5 SF. There is significant difference in these calculations, because pure horsepower calculation does not take into account the pump limitations (liner rating, strokes per minute limits, etc.). Some cases may require more pump rate, but these are usually accompanied with low flowing bottom hole pressures. This condition required less hydraulic horsepower. For safety and reliability, it is recommended that external stand-alone, independent drive pumps (DS Schlumberger, Halliburton, etc.) be provided in all cases. For purposes of discussion in this report Halliburton pump specifications have been used (not as a recommended vendor for these services although they are very capable, but because the author is more familiar with their equipment). If competing vendors are chosen, their equipment will be comparable and little modification except review of pressure-volume characteristics will be required. Figure H.4. shows this pumping spread for 8 each 600+ HP pumps.

The methods for specifying the hydraulic horsepower and numbers of units required to achieve the required injection pressure use the predicted pressure and pumping volumes from a two-phase flow model (for example DYN-X). Rather than applying a multitude of safety factors to each individual input value that affects the pumping requirements, the maximum theoretical values are used. Allowances are made for leakoff of fluid to the open hole (for example 10%) and calculations should be made to determine the numbers of units required for a given scenario. All these calculations should be done without applying safety factors and then an overall safety factor applied. The basis for calculating the required pumps follow;

Equation A.1

$$N_p = \frac{Q_k}{(1 - LO)} \frac{SF}{Q_u}$$

Where:

N_p =number of pump units (round to integer)

Q_k =design kill rate, [bpm]

SF=safety factory [*]

Q_u =max. Flow per unit, [bpm per unit] from manufacturer's data for 100% performance at anticipated discharge pressure (see Fig. H.5)

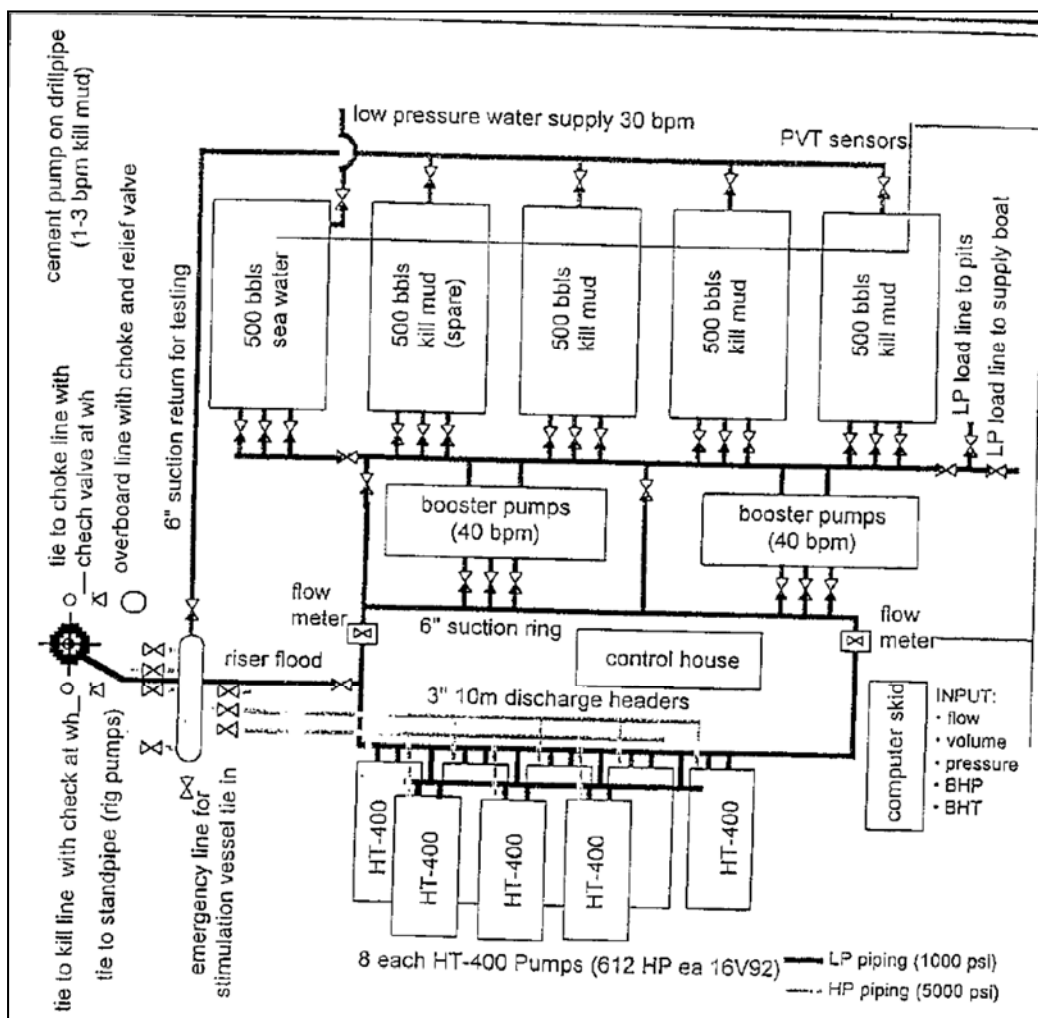


Figure H.4 Example Relief Well Pump Spread (Offshore)

Example

For Exploration type wells analysed using a two-phase dynamic kill model, 57.3 BPM kill rate was determined (maximum for 12-1/4" drilling phase). The maximum discharge from the pressure loss model is 740 psi (rounded to nearest 10 psi). From Figure H.5 the PVC discharge yields maximum available rate per unit, Q_u , of 12.5 barrels per minute per unit if maximum horse power is expended. Assuming 10% leakoff to the formation during the kill operation, LO becomes 0.10 given that the overall safety factor, SF, is 1.50. For this scenario, the required number of pumps will be;

$$N_p = 57.3 / (1 - 0.2) \times 1.5 / 12.5$$

$$N_p = 7.64 \text{ say } 8 \text{ units rounded to the nearest integer}$$

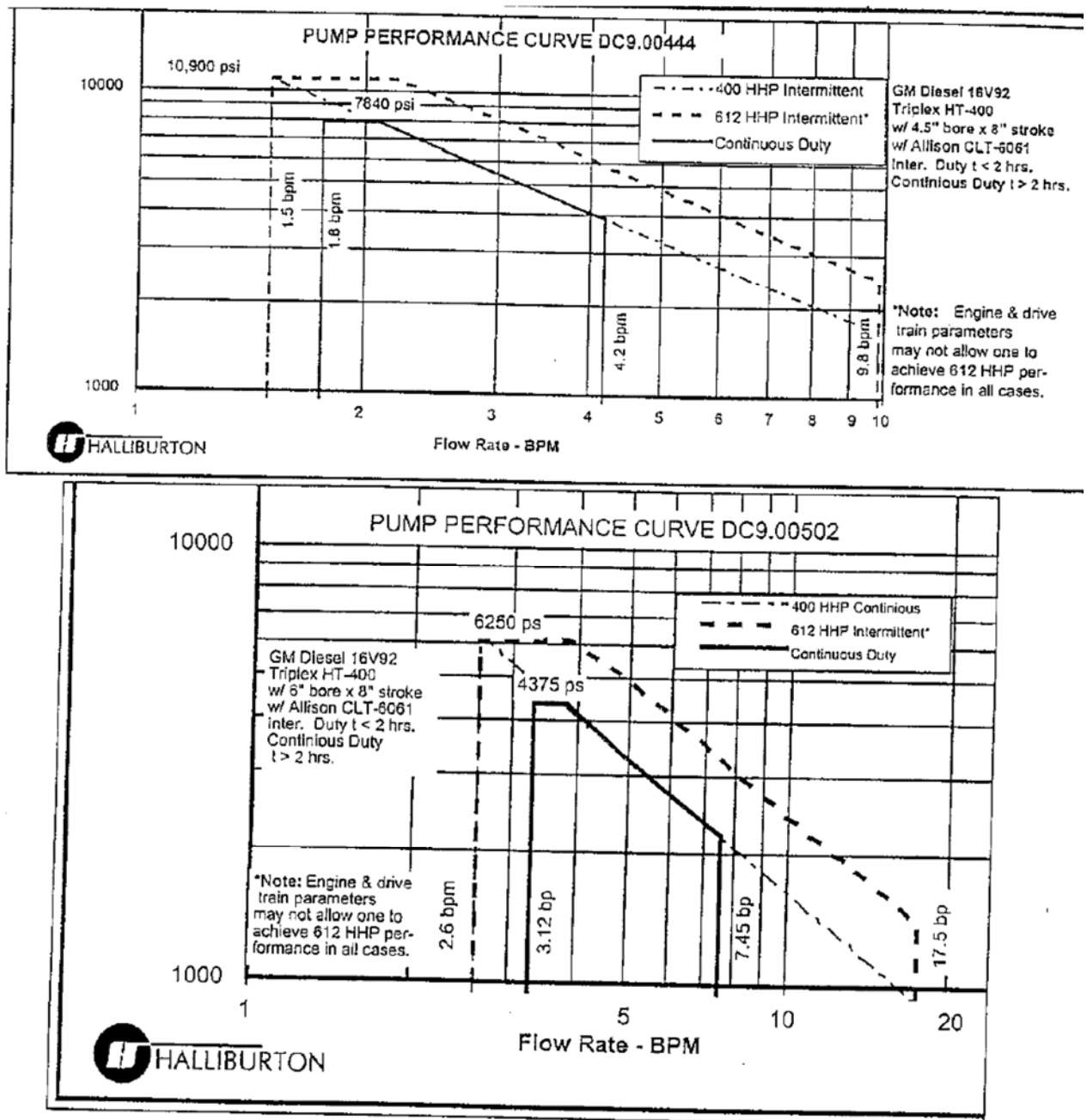


Figure H.5 Pressure Volume Curve
(Courtesy of Halliburton Energy Services, Duncan, OK)

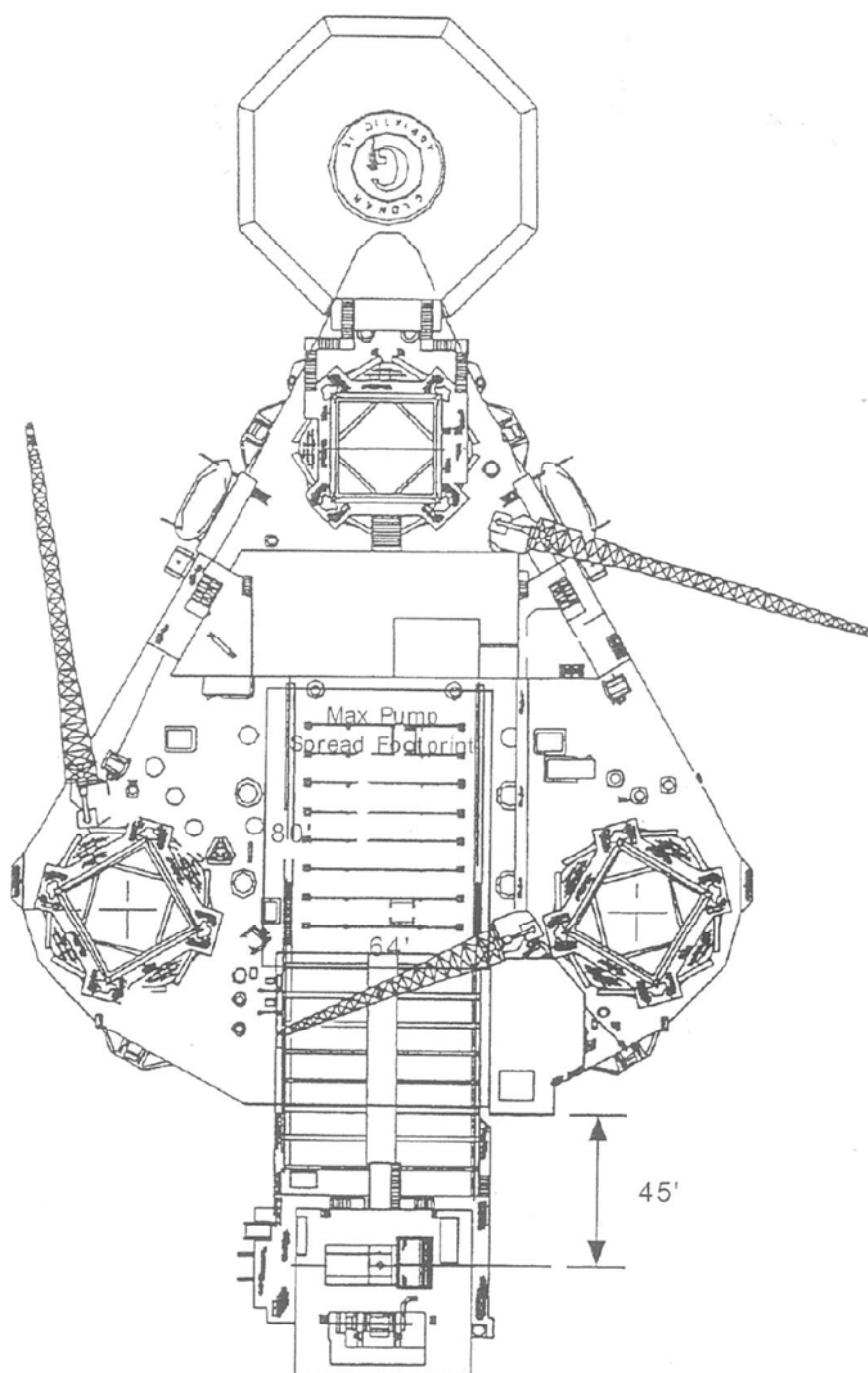


Figure H.6

10.8.8 CONCLUSION

The conclusion to be drawn is that the relief well can in fact be drilled to an interception of the blowout well with great confidence. Further, the directional and proximity drilling technology has advanced so that a wellbore interception is now the rule instead of the exception. While a relief well is necessary to control only a minor portion of blowout wells, it is a viable option in those situations where surface intervention is not a workable alternative.

10.9 RELIEF WELL STRATEGY

This discussion provides site specific details necessary for drilling a relief well in the Gulf of Thailand. It assumes the blowout is from a well that has penetrated the main producing interval of a development, delineation or exploration well. This section contains site specific relief well details while Appendix D contains the generic guidelines. (Note: Appendix D can be found in Volume II). Relief wells are not usually considered for the solution of shallow gas blowouts therefore this is not addressed in this plan.

10.9.1 Relief Well Target

The relief well will be aimed for an intercept of the blowout well as near to the source of the blowout as possible. For planning purposes in this report the target used to design trajectories is the top perforation in development wells and the top of the producing interval in drilling wells.

If the drill string is not in the hole or across the primary interval, an upper target must be selected based on the location of pipe or casing in the well. The worst case would be an interception target in the open hole that is void of pipe (casing or drill pipe). This would require the relief well to be aimed at the last casing shoe set, the 13-3/8" or 9-5/8" casing shoes for the 12-1/4" or 8-1/2" phases.

For this report the coordinate system at the surface is referenced to the surface location of the target well and UTM coordinates.

10.9.2 Positioning the Relief Well

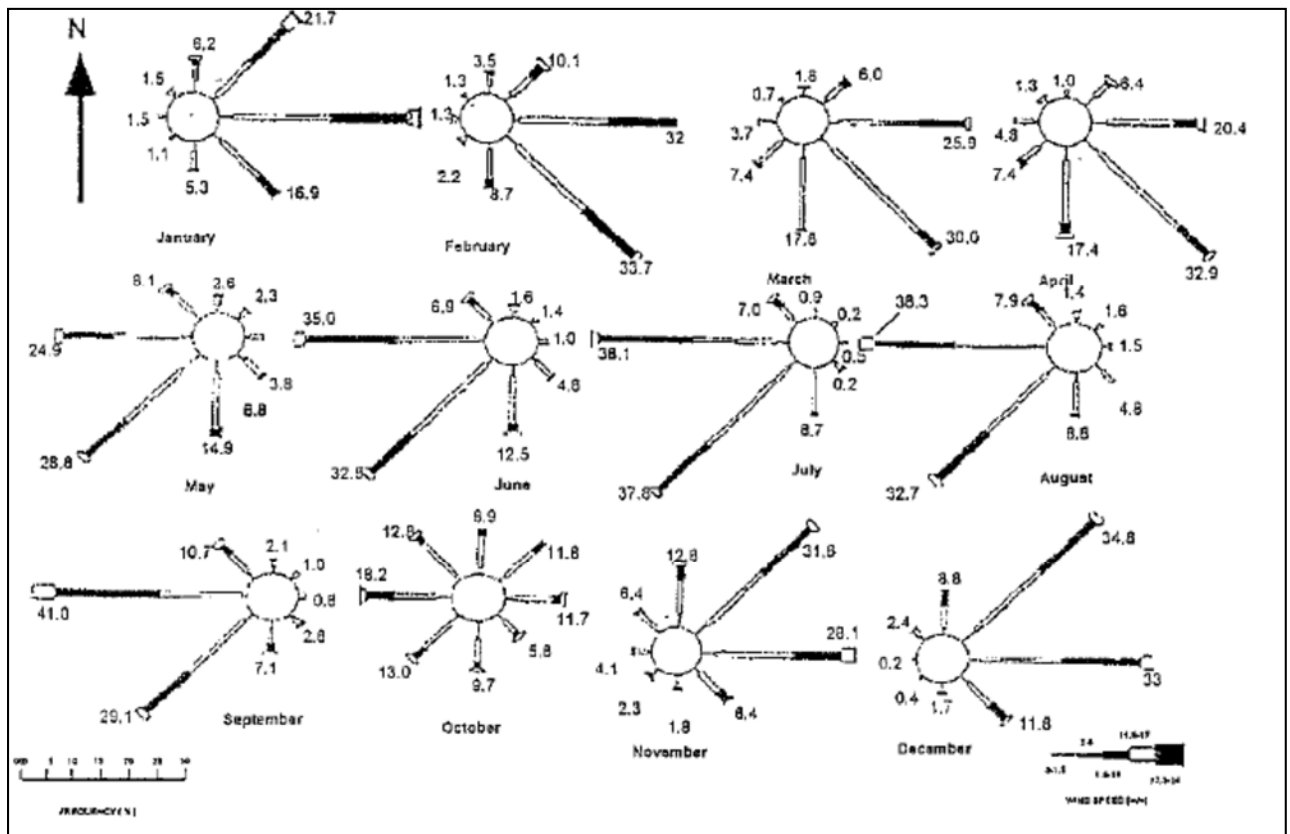
Positioning the relief well involves a number of objective and subjective considerations. Listed below are the factors taken into account for safe positioning of a relief well:

- Maintain at least a 300 m clearance from the blowout well surface location if the relief well is located in the SE quadrant (see figure I.3).
- Maintain a 600 m clearance from the blowout well surface location if the relief well is located in any quadrant other than the SE.
- Avoid the current gas dispersion streams by positioning the relief well where the Lower Explosive Limits 'LEL' of 5% by volume are within acceptable limits at every possible wind condition.
- Avoid seafloor obstructions in area; anchor pattern to leave 50 m of clearance from any obstruction (pipelines, flowlines, umbilicals, etc.).
- Avoid shallow gas zones that can be drilling hazards per the discussion of Section C.4 also see hazard map and relief well position for Bongkot platforms according to shallow gas hazard in Section 8).
- A position that accounts for favorable winds so that the relief well is upwind most of time. The major factors are the time of year and the time that will be required to drill the well Note: This will have to be determined on the fly and is not specifically addressed in this report.

The SE quadrant shown in Figure I.3 is the preferred all weather relief well position relative to the blowout. This is chosen as the position that is most likely to be upwind the majority of the time. The exception is the month of October when the winds are light and variable. Gas dispersion modelling has been done which indicates that the 300 meter distance is acceptable for the October wind conditions. IF necessary the relief well can be positioned downwind, but distance from the blowout must be increased to 600 m. The basis for this is taken from gas dispersion modelling where the blowout rates were used to determine LEL for the worst case wind conditions (slight

breeze and a subtropical inversion reducing natural mixing of the air). More detail of the gas dispersion analysis can be found in Section G.5. Figures I.1 and I.2 show the wind roses used to make this determination and the result of the gas dispersion analysis.

If may be possible to position a well inside the exclusion zone, but this will need to be based on actual conditions (e.g. air quality monitoring). Choosing a location not meeting the above conditions can only be done if conditions at the blowout location do not jeopardize the drilling crew or equipment safety. If the risk is excessive, then the alternative profiles (Double-S to vertical shapes) should be chosen for the relief wells.



(Figure Wind Rose Data (1987-1992))

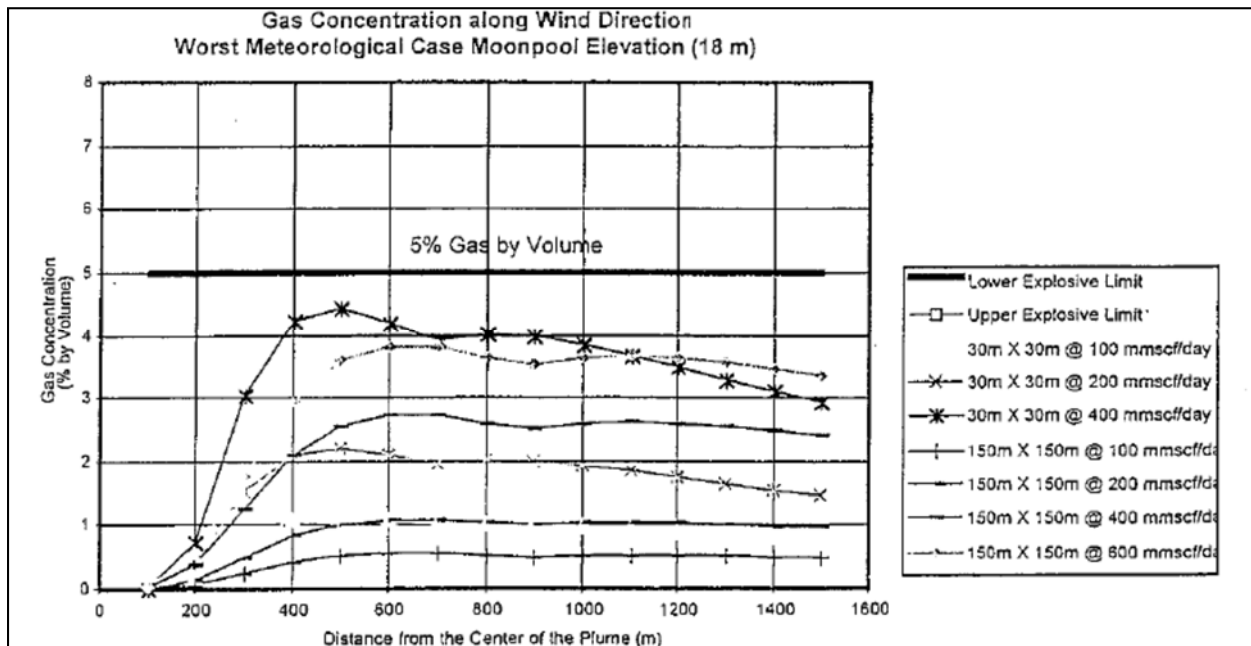


Figure 2 Gas Dispersion Analysis Summary

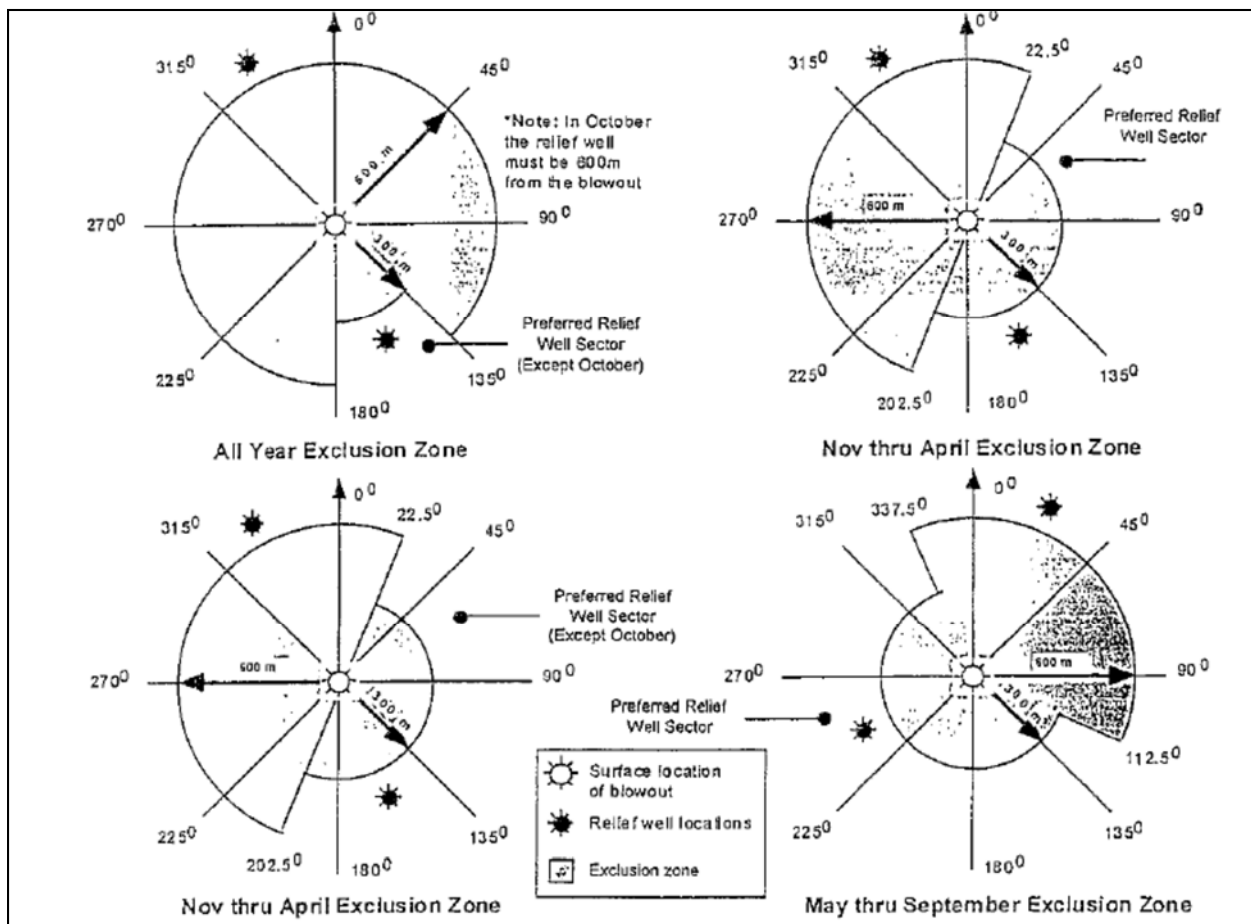


Figure I.3 Exclusion Zone for Relief Well Placement

10.9.3 Relief Well Trajectory

The relief wells are designed to have the relief well lined up at least 100 m before reaching the target and to have no more than 10 degrees of combined azimuth and inclination difference from the blowing well at the intercept point. The relief wells should come within the effective range of the proximity tools (25 to 50 m displacement) at the first detection point and approximately 150 m before drilling to the target “(e.g. reservoir penetration or last casing shoe). When within this range, the proximity tools will be run to locate the target and direct the relief well to this revised target. The azimuth direction will be approximately the same as the blowing well. A slight lead to the left is preferred in order to allow the well to turn to the right and drop angle as the final corrections are made to the target (about 5 to 10 degrees will be adequate to meet this criteria). For purposes of design and to account for some right-hand walk a 6 degree lead angle has been chosen for planning purposes.

The simplest and shortest drilling distance for the relief well was chosen whenever possible. This is a simple build and hold (J-curve) trajectory. For a J-curve, the surface location is placed for the minimum required displacement, therefore minimum lineal drilling distance. This is the chosen relief well plan for the intercept. The first detection target is the blowout well at a point approximately at the reservoir penetration.

The logic for presenting these minimum displacement locations is to have the option to minimize the relief well drilling effort should a blowout occur during a period of the year when historic wind conditions are favorable. Also, if the well is blowing out underground and no slick was anticipated or being generated the distance to blowout surface location may not be a factor.

J-curve (build and hold) and S-curve

Relief well trajectories designed for this project were put into three (3) categories and are summarized below:

- Relief Well A – J curve build and hold positioned at least 600 m from the blowout platform location.
- Relief Well B-S-curve to vertical positioned 300 or 600 m from the blowout bottom hole location. These would be the relief wells needed for a vertical well blowing out on a platform or a floating rig. Two cases are considered for a development well and an exploration well.
- Relief Well C-A vertical well positioned at least 600 m from the blowout platform location. This would cover the relief well needs of wells BK-4-D, F, G and L along with BK-6-A and D. These wells are S-curve wells with the bottom hole portion of the well at least 600 m from the platform. The wells are assumed to be close to vertical at the top of reservoir, which would allow a vertical relief well to be drilled.

Table I.1 gives the surveying data and ties for the relief wells mentioned above.

Well	Top Perf m TVD	Top Perf Location		Angle deg	Azimuth deg	Displ to plat	Direction from plat	Relief Plan	Well Displ	Sur Loc		RW Displ to Plat	No te
UTM N	UTM E									UTM N	UTM E		
BK-1-B	1308	889,175	865,859	38.76	323.96	367	358.13	37	176	889,279	865,803	479	*
BK-1-C	1415	889,592	866,041	49.65	355.57	851	22.83	6E	248	889,611	866,050	876	
BK-1-E	2048	888,652	865,516	32.25	58.52	250	231.34	30	127	888,544	865,408	402	*
BK-1-D	1493	888,516	866,783	25.41	109.04	1111	105.14	25	96	888,427	866,692	1053	
BK-1-F	1502	888,862	865,574	31.65	294.24	147	291.51	30	127	888,978	865,690	171	*
BK-1-G	1433	887,985	865,700	45.82	184.21	823	180.77	6E	248	888,003	865,718	805	
BK-1-H	1458	885,953	866,871	43.65	82.59	1169	82.87	6E	248	888,707	866,625	920	
BK-1-K	1789	888,109	865,237	5.62	98.35	845	214.14	Vert	0	888,109	865,237	845	
BK-1-L	1389	888,355	866,123	18.52	89.98	512	137.71	13	37	888,318	866,086	517	
BK-1-M	963	887,814	866,023	59.88	164.00	1042	162.57	5C	494	887,678	865,887	1144	
BK-2-A	1531	885,137	868,324	56.79	304.10	1241	340.71	6B	332	885,412	868,599	1453	
BK-2-B	1532	884,091	867,821	52.74	271.73	921	277.82	6B	332	884,423	868,153	739	
BK-2-C	1418	883,900	869,352	35.53	196.00	622	96.07	30	127	883,935	869,387	654	
BK-2-D	1434	883,989	869,604	52.14	86.99	870	88.47	6E	248	883,741	869,356	682	
BK-2-E	1250	883,428	868,208	40.13	224.39	752	224.36	37	176	883,551	868,331	578	*
BK-2-F	1318	883,255	868,179	43.45	206.92	902	217.98	37	176	883,335	868,259	790	
BK-2-G	1515	882,782	869,324	54.54	177.02	1323	153.50	6B	332	882,765	869,307	1331	
BK-2-H	1278	883,285	869,381	53.68	139.26	939	136.45	6B	332	883,058	869,164	995	
BK-2-K	1519	883,184	868,040	39.15	157.04	839	158.62	37	176	883,115	868,971	883	
BK-2-J	1476	884,026	866,508	49.88	269.65	2227	271.55	6E	248	884,274	866,756	2002	
BK-2-L	1343	884,127	867,417	58.20	277.28	1327	276.98	6B	332	884,456	867,746	1103	
BK-2-M	1365	882,951	867,319	51.82	236.15	1741	234.35	6E	248	883,157	867,525	1455	
BK-3-A	1515	887,976	867,065	57.15	288.29	1277	266.06	6B	332	888,291	867,380	965	
BK-3-B	1529	888,334	867,528	39.01	281.51	854	288.43	37	176	888,506	867,700	777	
BK-3-C	1549	888,641	868,837	37.21	48.51	763	40.81	37	176	888,509	868,705	577	*
BK-3-D	1551	888,877	869,585	58.73	56.83	1488	56.88	6B	332	888,589	869,307	1107	
BK-3-E	1450	887,511	867,228	49.73	258.13	1241	243.54	6E	248	887,754	867,471	922	
BK-3-F	1446	887,757	867,818	24.92	241.79	804	239.49	25	96	887,842	867,903	489	*
BK-3-G	1453	887,919	868,092	13.72	328.39	286	239.58	13	37	887,938	868,111	260	*
BK-3-K	1436	887,192	867,901	58.74	204.50	975	206.55	6B	332	887,330	868,039	793	
BK-4-D	1542	895,099	863,153	48.54	52.39	951	52.00	6E	248	894,903	862,957	686	
BK-4-H	1459	894,465	863,041	38.99	90.38	647	93.76	37	176	894,289	862,865	518	*
BK-4-G	956	894,359	862,615	45.75	123.88	265	124.11	6E	248	894,153	862,409	356	*
BK-4-F	1407	895,026	861,767	18.27	309.93	815	309.51	13	37	895,054	861,795	812	
BK-4-K	1681	893,714	861,535	46.99	194.99	1171	227.33	6E	248	893,778	861,589	1080	
BK-4-L	934	894,176	862,595	60.38	147.17	387	148.87	6B	332	893,996	862,416	512	*

Well	Top Perf m TVD	Top Perf Location		Angle deg	Azimuth deg	Displ to plat	Direction from plat	Relief Plan	Well Displ	RW UTM N	Sur Loc UTM E	RW Displ to Plat	No te
BK-5-B	2041	886,437	861,957	60.2	341.81	2,275	346.9	80	519	887,960	862,161	6552	
BK-5-C	1534	887,141	864,694	63.1	67.60	2,404	67.5	63	560	886,884	864,198	7834	
BK-5-D	2120	885,386	864,325	54.97	112.73	2,031	114.3	6E	448	885,249	863,899	9379	
BK-5-E	1329	886,761	862,184	40.34	6.02	612	28.3	40	269	886,492	862,179	6019	
BK-5-F	1584.7	884,993	862,426	50.84	159.23	1,229	2.2	6E	394	884,638	862,255	9870	
BK-5-G	1518.9	886,169	862,569	31.95	125.87	108	61.5	32	183	886,075	862,412	8432	
BK-5-H	940	886,055	862,982	60.92	104.86	535	108.1	6B	529	885,965	862,461	8543	
BK-5-J	1320	886,196	862,311	38.89	61.72	164	8.0	38	253	886,140	862,065	8374	
BK-5-K	2032	885,039	862,790	47.97	164.29	1,224	165.0	6E	358	884,704	862,663	9807	
BK-5-L	1624	883,710	862,406	60.79	178.00	2,512	178.5	6B	527	883,187	862,342	11320	
BK-5-M	2329	884,755	864,048	37.27	125.44	2,144	132.8	37	236	884,645	863,844	9968	
BK-6-A	1591	879,428	870,511	52.64	232.29	1697	233.15	6E	248	879,624	870,707	1423	
BK-6-B	1432	880,703	870,864	55.07	283.48	1037	284.37	6B	332	881,026	871,187	895	
BK-6-C	1214	881,825	871,141	68.33	328.46	1560	332.19	6C	494	882,083	871,399	1704	
BK-6-D	1375	881,102	872,217	30.47	30.50	743	27.96	30	127	881,038	872,153	657	
BK-6-E	1395	879,806	871,396	42.98	214.05	795	216.46	6E	248	879,945	871,535	602	
BK-6-F	1568	880,468	871,475	38.97	273.11	394	272.97	37	176	880,642	871,651	293	*
BK-6-G	1353	880,290	872,436	47.95	106.20	590	105.26	6E	248	880,052	872,200	515	
BK-6-H	1456	880,282	871,771	33.65	223.79	191	210.82	30	127	880,370	871,859	76	*
BK-6-J	1835	881,285	870,828	44.94	287.20	1337	308.89	6E	248	881,522	871,065	1343	
BK-6-M	971	879,971	872,089	46.18	154.04	523	155.09	6E	248	879,862	871,980	594	*
BK-7-B	1857.4	886,264	874,780	60	323.77	2,326	301.54	60	516	887,875	875,121	1819	
BK-7-E	2331.3	887,218	874,516	44.91	271.82	1,751	327.71	6E	321	887,538	874,499	1955	
BK-7-F	2036.6	886,292	875,355	39.91	269.61	642	359.12	6E	264	886,555	875,330	721	
BK-7-G	1611.5	885,240	875,946	12	227.20	66	230.50	vert	40	885,266	875,916	300	*
BK-7-H	1650	886,199	876,120	39.73	123.80	149	124.07	6E	262	885,969	875,994	313	*
BK-7-L	1581.2	884,720	876,079	60.21	213.38	1,564	183.00	6B	519	884,967	875,622	1367	
BK-8-	Later												
BK-9	Later												
BK-10	Later												
Platform	Location	North	East							North	East		
	WP1	888,908.00	865,711.00							WP6	880,445.60	871,868.60	
	WP2	883,965.70	868,733.90	Platform Location						WP7	886,282	875,997	
	WP3	888,063.80	868,338.60	Platform Location						WP8	888,931	873,025	
	WP4	894,507.43	862,395.85							WP9			
	WP5	886,221	862,473.7							WP10			

Note: Special consideration may be required for these locations due to the time of year and the wind patterns at that time of year.

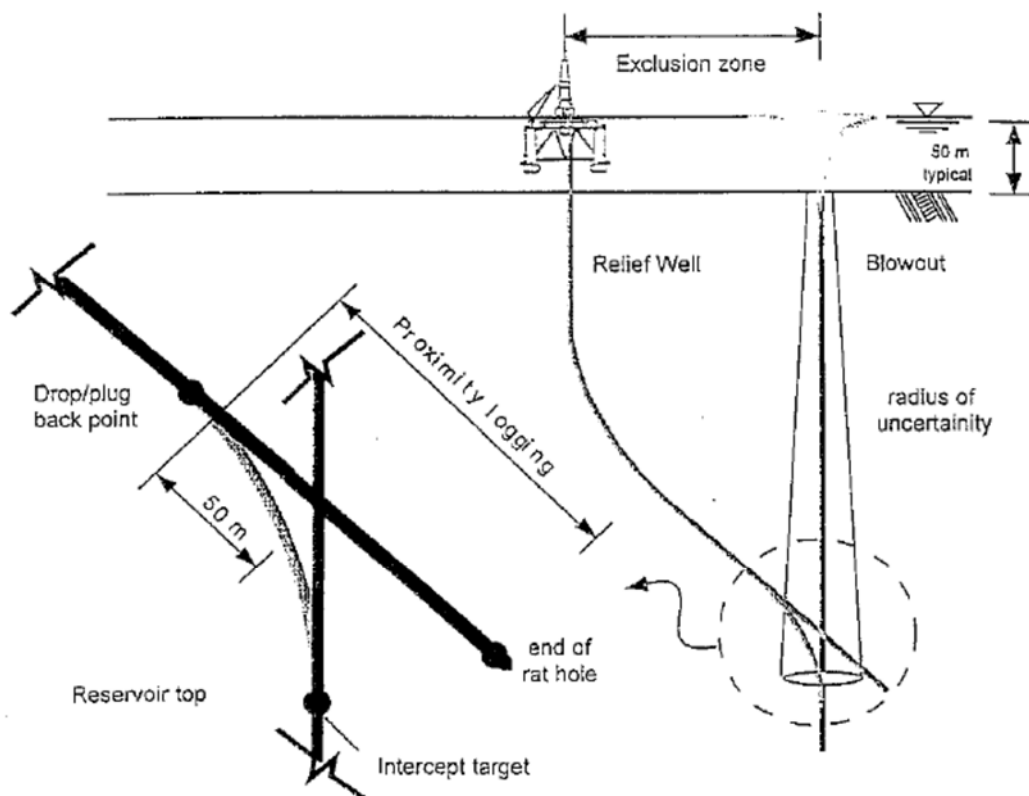


Figure I.4 Type A Relief Wells

10.9.4 Shallow Gas Discussion

As of April 97 the hazard maps for shallow gas for the Bongkot Field and surrounding area is not complete. The mapping done to date has been for the platform areas only. Therefore the choice of locations for the relief wells has ignored the fact that there may be a shallow gas hazard at the optimum location. The optimum location is that position that will yield the minimum lineal footage to reach the target. For example, for high angle wells the relief well location was moved out to a position near the reservoir target. It may well be that these locations are over shallow gas drilling hazards, therefore an investigation must be undertaken before a rig, especially a jack up is moved to drill a relief well. The options for addressing these problems are summarized below:

- If a semi rig is available (either on the market or under contract to PTTEP for exploration during the 1998 exploration campaign), a pilot hole could be drilled riserless to test for the presence of shallow gas.
- Seismic interpretations can be performed for each relief well location (from available data 3-D seismic survey data). This can be done now for all locations chosen for relief wells (perhaps cost prohibitive) or done on a crash program while the rig is being prepared to move onto the relief well location. If the interpretations show a hazard then it can be tested with a pilot hole or an alternative location chosen. Waiting is not seen to have an impact on the timeline to drill the relief well as one can be doing the interpretation while the rig is under tow and other equipment made ready to spud the well. However the window for moving on to the relief well after being given the approval to proceed is approximately 6 days (given there is a rig in the area that can be moved to the Bangkok area). If the interpretation takes more than 6 days it will impact the relief well drilling spud date.

These operational parameters will have to be reviewed if relief well projects become a reality to choose the most expeditious means to drill the relief well given the potential for shallow gas hazard.

10.9.5 Casing Design and Seat Selection

The relief well casing design is the same for a development or exploration type well. This will meet the pumping requirements for the dynamic kill. Additional factors have been considered and evaluated in addressing the relief well design and they are the;

- Effects of well casing configuration on the friction and flow rates required during the kill operation.
- Implications of setting an additional casing string to combat downhole problems encountered during drilling, i.e. can the objective still be attained if a further reduction in hole size is required or addition strings set?
- Realistic possibilities of individual zones being artificially pressured or depleted and is there information to support this position.

In addition to the above, certain questions should be reviewed prior to spudding the relief well to take advantage of the most current information, and these are;

- Has the target location changed significantly since the relief well plan was developed?
- Were there complications encountered in the original blowing well during the up hole sections which could threaten the success of the relief well? How will these be averted?
- Will the casing scheduled have to be modified to meet the directional drilling objectives required to intercept the blowing well?
- Was there an unanticipated presence of a corrosive or toxic fluid such as H₂S that requires special consideration?

Casing Program

The casing program for a development or exploration relief well has taken the above list of considerations into account. The result was basically the same casing program used in the well with one exception; a larger surface casing was used to provide for any contingencies requiring that an additional casing string be run due to hole problems or mechanical difficulties. This is not to say that extenuating circumstances such as an underground flow may require re-evaluation. If unanticipated pressuring of a shallow interval occurs, additional casing may be required. For the purposes of this report, subsurface charging has not been considered because it is believed that the relief well can be spudded and drilled to objective TVD before time dependent charging can become a factor in the shallow horizons. Also, the likelihood of shallow charging is dependent upon having a shallow casing leak, which is a low probability scenario, but should be considered if a relief well becomes a reality.

CAUTION Charging of subsurface zones must be reviewed prior to spudding the relief well to make assurance that it does not represent a drilling hazard.

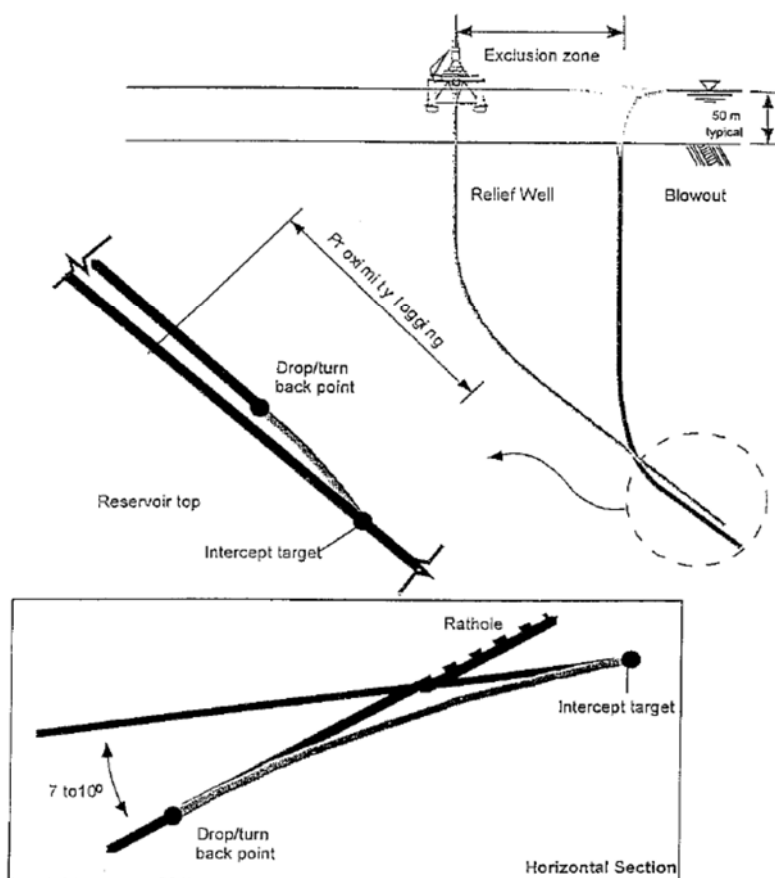


Figure I.5 Relief Wells for Inclined Targets

A 7" liner would not be required under most circumstances unless hole conditions require its use. The author saw no reason to program the 7" liner and 6" open hole to target PTTEP depth, but leaves this as a contingency should it be needed to accomplish the interception. This option would have to be thoroughly evaluated because with its use would come a host of additional problems and limitations. With the 7" liner in place it will be difficult or impossible to plugback the relief well to make directional corrections. Thus the 7" liner will induce additional risks to the relief well should interception or pumping to kill fail in the initial attempts. Table 5.2 shows the recommended casing program for all relief wells.

CAUTION Setting a 7" liner must be done only as a last resort and then only after very careful review. Note that this will certainly limit any future directional correction and severely restrict the flow during the kill operation.

Table I.2 : Relief Well Casing Program

Casing Size	Casing point objective	Casing description	Drift ID. (inches)	Internal Yield
30"	Approx. 60 m. below sea floor	1.5"Wall LYNX-HD		
13-3/8"	Approx. 450 m.	68 ppf N80 Buttress	12.26	5018 psi
9-5/8"	Approx. 1060 m TVD	53.5 ppf 95 grade New Vam	8.525	9410 psi
7" Liner*	To be set only if hole conditions dictate to reach objective	32 ppf 95 grade 0 VAM	5.969	10760 psi

*Note: Only if required by hole conditions.

Well Control Considerations

The blowing well may introduce new pressure environments in the formations through which the relief well must drill. This may be characterized by over pressured or depleted zones.

When considering a surface blowout after the 9-5/8" casing has been set above the reservoir, it is assumed that the integrity of the 9-5/8" casing and casing shoe are maintained and no underground flow has or can occur. Under this scenario, no unusual or abnormal pressures should be encountered above the 9-5/8" casing setting depth in the blowing well. It is believed that drilling of the relief well should proceed according to the program to the 9-5/8" casing point (approximately 1060 m TVD) without major concern.

Before reaching the 9-5/8" shoe all the BOP equipment should be completely tested to the maximum rated pressure and the entire compliment of fully tested kill equipment and kill weight mud should be on hand. From that point forward, precaution must be exercised to control any possible influx. The increased trips necessitated by the directional work will require close control of tripping practices.

Should hole conditions in the relief well deteriorate to the point that progress cannot be made without casing the open hole section, a 7" liner may be set to provide the necessary protection. This should be avoided if possible because it:

- Limits the options for directional correction
- Restricts the use of some directional equipment
- Increases the duration of drilling activity and
- Adds additional friction restrictions for the kill operation.

Should the 7" liner be required, a packoff liner hanger should be installed, and the liner lap dry tested and pressure tested before drilling new open hole.

Subsurface Charging

An underground blowout can cause subsurface charging that can create a drilling hazard for the relief well. If this is the case, careful reservoir modelling will need to be undertaken to determine at what distance the relief well can approach the thief zone without encountering a well kick. Since the relief well target will be the producing zone, this may not be of concern, however careful study is warranted.

The reason for penetrating the blowout reservoir before setting the 9-5/8" casing must be carefully studied before commencing the relief well. Factors such as a thinning of overlying formations or faulting must also be taken into consideration in drilling the relief well.

Before drilling into each zone containing possible abnormal pressures, kill weight mud must be available to control an influx. Tripping practices must be closely monitored with an emphasis on minimal off bottom time. Excessive logging or wiper trips may potentially cause problems (reason for specifying proximity logs to be run inside the drill string rather than in open hole). IF extended periods of logging are required, strong consideration should be given to hole conditioning trips between runs.

Under this scenario, the greatest probability of problems on the relief well would be expected between the 9-5/8" shoe and the interception point. The presence of a high volume underground flow could create a situation that could require the 7" liner. The same complications discussed earlier would be further exacerbated by the requirement for a high rate kill operation.

Operational Comments

As the relief well converges on the blowing well, it is often difficult to anticipate at what point the relief well may begin losing fluids to the blowing wellbore. With this in mind, it must be possible to immediately switch the relief well from drilling to the kill operation at any given time during the final approach to the target wellbore. Therefore, it is imperative that prior to the final approach, all preparations for the kill operation must be complete. In this case, the point at which preparations for the kill operation must be fully completed is before reaching 9-5/8" casing setting depth. Once full wellbore communication is established, the kill operation can continue according to plan.

After locating the target wellbore and before drilling the final segment to interception under either scenario, a trip should be made to remove all unnecessary restrictions, i.e., drill collars, heavy weight drill collars, subs, etc., from the drill string. In this manner the friction losses inside and outside the drill string will be minimized during the kill operation.

10.9.6 Tool Specifications

Directional Survey Tools

Listed below is the directional survey program recommended for the exploration and delineation type wells

42" Hole Section	Check verticality teledrift
Inside 30" Casing	None
17-1/2" Hole Section	Single shot in the middle of the phase and 1 single shot per trip and one battery tool gyro at the end of the phase
Inside 13-3/8" Casing	None
12-1/4" Hole Section	Single shot in the middle of the phase and 1 single shot per trip and one battery tool gyro at the end of the phase
Inside 9-5/8" Casing	None
8-1/2" Hole Section	Magnetic multishot
Inside 7" Casing	No survey

The directional survey program for the relief well follows the basic plan of the program for the producing wells, except for the additional equipment needed in the event a 7" liner must be set, and 5-7/8" hole must be drilled to interception. Listed below is the recommended program:

42" Hole Section	Check verticality with the MWD at the casing point.
Inside 30" Casing	No survey
12-1/4" Hole Section	Drill with an MWD taking data while circulating after drilling each stand
Inside 9-5/8" Casing	Run a North seeking gyro at 10 m stations to 9-5/8" shoe
8-1/2" Hole Section	Drill with an MWD taking data while circulating after drilling 10 m or use of a proximity steering tool
Inside 7" Liner	If a 7" liner is required run a North seeking gyro at 10 m stations to 300 m above the liner top and tie survey data back to the survey inside the 9-5/8" casing
6" Hole Section	Drill with MWD taking data while circulating at intervals dictated by situation or proximity steering tool.

Drilling Tools: The drilling tools required to drill the relief well may vary somewhat depending on the exact requirements and availability at the time. Please see Appendices: Relief Well Planning for a list of equipment recommended.

10.9.7 Modelling Criteria

For this project the DYN-X computer model was employed to describe the relief well and blowout well scenarios. This model considered two-phase steady state gas and oil flow for various pumping rates. The model took into account the geometry of the well, the inflow performance of the reservoir, reservoir fluids and its non-Newtonian behavior and the rheology of the kill fluid. Both sonic (theoretical maximum) and sub-sonic exit conditions were analysed. The models were developed by Dr. Adam. T. Bourgoyne of Louisiana State University on a consulting basis to ABEL Engineering. The models take into account experimentation at LSU where the exit conditions for gas in large diameter pipes have been observed and mathematical descriptions of the pressure relationships developed. The computer models and the equations used are documented in the text Firefighting and Blowout Control by L. William Abel et al. The model is Microsoft Excel™ spreadsheet (runs on the Mac in Version 5.0 and on a PC in Windows Excel™ Version 5.0).

DYN-X was used to investigate several scenarios of blowout conditions and to establish the kill pumping criteria. In addition to kill requirements, the model was used to predict a gas flow rate based on certain assumptions regarding reservoir parameters.

10.9.8 Blowout Scenarios

There are quite literally an infinite number of scenarios for loss of control of a well, however for planning purposes two general categories were considered:

- an underground blowout or
- a surface blowout (e.g. a leak at the BOP level)

All the investigations undertaken were subsets of these two general categories. Some were run to established boundary conditions. The more reasonable or likely situations are noted. Full reservoir potentials were considered for three scenarios. The geometry variations included drillpipe and drill collars in the hole and out of the hole. For each scenario, the wellbore with the shortest path was considered. For some cases, the wellbore with the longest path was used for comparison. In conjunction with this approach, only those scenarios that are both reasonable and feasible were reported and used for designing the pumping requirements. The results are not considered final and adjustment of the kill requirements is anticipated if an actual relief well project becomes a reality.

From the reasoning above the following scenarios were considered for development and exploration wells:

SCENARIO I:

Well is blowing out through a leak in the BOP stack during the 8-1/2" drilling phase. The flow is from the target reservoir at full reservoir potential. There are no leaks in the open hole or cased interval. The drill string is in the hole as per Figure I.6.

SCENARIO II:

Well is blowing out underground from the reservoir to the shoe to the 13-3/8" casing during the 12-1/4" drilling phase. The flow is from the target reservoir at reduced reservoir potential. The drill string is in the hole per Figure I.7

These scenarios are considered to cover the worst case and likely well conditions if the well does blowout. They are **not** a risk assessment that a blowout is likely to occur. A blowout is considered

a very unlikely probability in the first place, but this probability cannot be reduced to zero, therefore a set of “likely” scenarios has been examined.

Scenarios Commentary

An abbreviated system has been chosen for the description of the various scenarios. This is exhibited in the above scenario descriptions. A Roman numeral system describes the physical geometry and exit condition where I, II and A are the three basic physical geometry's scenarios:

I: 9-5/8" casing set, reservoir penetrated with open hole, BOP leaking, casing holding (not ruptured) and no underground flow.

II: 13-3/8" casing set, reservoir penetrated with open hole, underground flow, BOP and casing holding.

A: Designation means that the drill string is in the hole.

B: Designation means that no drill string is in the hole.

xx mD: Designation means that "xx" millidarcies were considered for the strength of the reservoir.

yy Nm: Designation means that "yy" meters of reservoir penetration were considered.

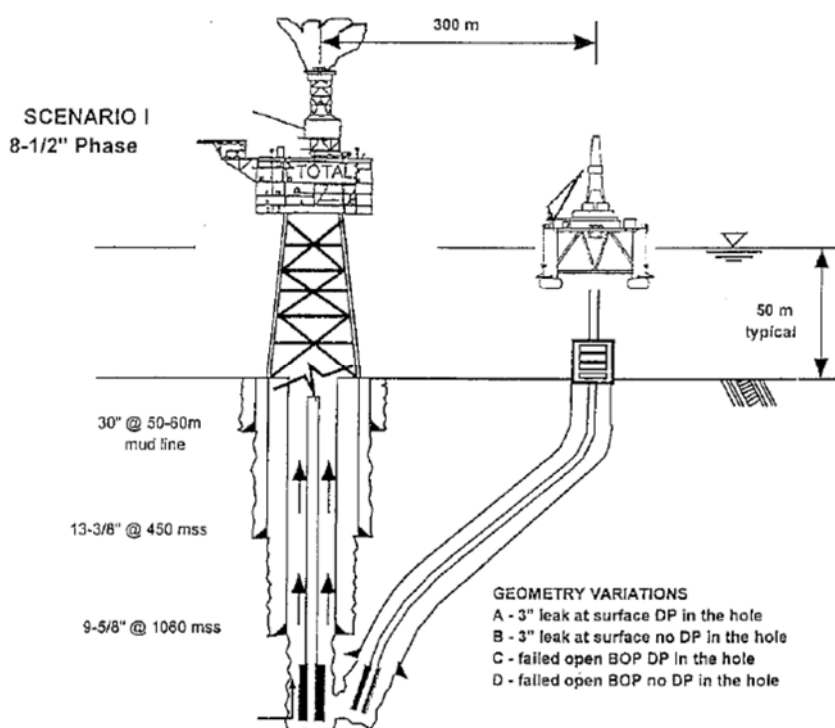


Figure I.6: Scenario I

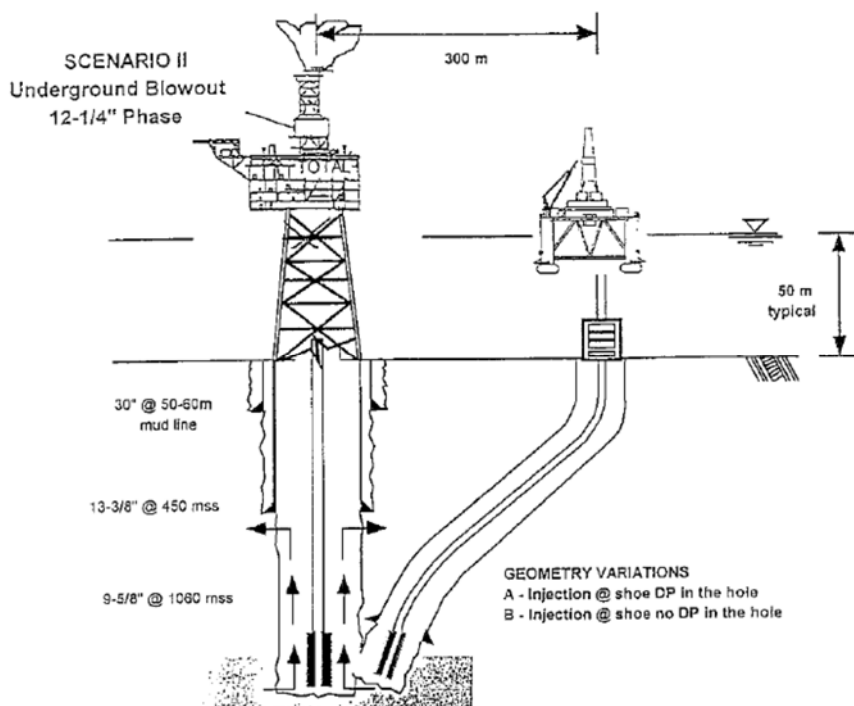


Figure I.7 Scenario II

10.9.9 Kill Fluid Design

Kill Fluid

This report used experience and computer simulations to determine that the most logistically sound kill fluid is a water based drilling mud similar in density to what was used to drill the well. The objective is to slightly overbalance the reservoir pressure, but not fracture the open hole interval during the kill procedure. Note that the kill pump rates calculated will certainly produce an equivalent circulation density that will exceed fracture gradient if not mixed with gas in the wellbore. Therefore, it will be necessary to reduce the pumping rates as the well comes under control to avoid fracturing and leak off of the fluid. Procedural recommendations are contained in a latter section of this report. The kill rheology chosen for the relief well kill operation and computer modelling follows:

Development

- SG = 1.2
- 8-1/2" Hole
- PV = 8 YP = 17
- Fann 600 = 25 Fann 300 = 33

Exploration

- SG = 1.4
- 8-1/2 Hole"
- PV = 10 YP = 14

- Fann 600 =24 Fann 300 =34

The important factor for the kill fluid rheology is that it has sufficient density to slightly overbalance the reservoir when static but still remain “thin” enough to be pumped at the necessary rates. The properties stated above are not absolute values but reasonable estimates for modelling purposes and estimation of horsepower requirements. These values were taken from the chart shown in Figure C.8. Should a relief well become a reality, the pumping requirements must be reviewed carefully to insure that the actual properties do not exceed the above values by more than 20% as the frictional losses could be significantly larger. Hydraulic calculations for each scenario considered are contained in Appendix E, Section E.3.

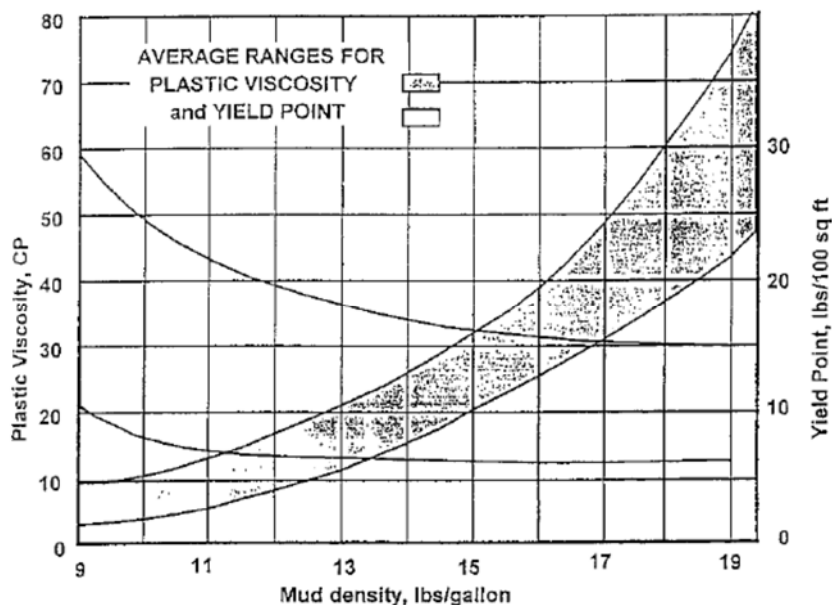


Figure I.8

Fracture Avoidance / Leak Off

During the kill operation when fluid is placed in the blowing well, the objective will be to overcome flowing bottom hole pressure. Thereafter the bottom hole pressure exerted must then slightly overbalance the static reservoir pressure. In no case should the pressure profile in the open hole interval (reservoir to the last casing shoe in the blowing well) be allowed to exceed fracture gradient. If massive fracturing is allowed, the majority of the kill fluid will be lost to the fracture and it is doubtful the well will be killed.

Some leak off will most likely occur during the initial stages of the pump to kill operation. For this report, leak off has been estimated to be 10% of the volume being pumped. Adjustments of the pumping rate have been increased accordingly. For example if the computer model says that 42 barrels per minute is required to kill the well, then 46.2 barrels are modelled for the frictional model.

Fracture avoidance may be very difficult to maintain, but never-the-less it is the most logical and prudent procedure to follow during the kill operation. To this end, the pressure profiles for various pumping rates of kill fluid have been reviewed to see that fracture gradient is not exceeded at the recommended pumping rates. A procedure will need to be developed to prevent fracture of the open hole during the kill operation. DYN-T transient analysis is recommended to the guide actual operation.

10.9.10 Pumping Requirements

Of the scenarios considered, scenario I-A and II-A are more likely to present themselves than scenarios I-B and II-B. Table C.6 contains summaries of the computer investigations. All the computer results are contained in the appendix of this report should more detail be needed.

All other scenarios are considered to be subsets of the above. For kill rates determined to be greater than 50 barrels per minute the scenario were reviewed carefully and all were considered to be either unreasonable or boundary condition and unlikely to occur. In the event that a blowout does occur that matches these models for gas rates and pump rates greater than 50 barrels per minute, multiple relief wells may be needed.

(Kill Pump rates, Pump Spread, FBHP and Blowout Flowrates)														
DYN-X			CALCULATED PARAMETERS											
Qgas mmscf/d	Coil std/d	FBHP* psi	Mud Hydro	System Losses	Pump Press	Min HHP	BPM w/LO	SF	Assm'd LO	BBLS/ Pump	HHP/ pump	Num pumps	actual HHP	Case
218.7	4374.2	3055.9	-1188	325	1868	1461	31.91	1.5	10%	8	612	6	3672	Dev 3" leak DP
308.9	6177	2746	-1188	682	1558	1838	48.14	1.5	10%	8	612	9	5508	Dev 3" leak NDP
364.5	3243	5528	-2155	488	3373	2537	30.69	1.5	10%	8	612	6	3672	Exp 3" leak DP
583.6	5193	5048	-2155	1099	2892	3413	48.16	1.5	10%	8	612	9	5508	Exp 3" leak DP
47.9	959	965	-2313	874	-1348	n/a	41.11	1.5	10%	12	612	5	3060	UGBO Dev Norm
66.1	595	5374	-2155	670	3218	n/a	20.00	1.5	10%	12	612	4	2448	UGBO 9m pen
264.5	5288	94	-1188	346	-1094	n/a	33.03	1.5	10%	8	612	6	3672	Dev 3" leak DP Horz
417.8	8356	149	-1188	730	-1039	n/a	49.99	1.5	10%	8	612	9	5508	Dev 3" leak NDP Horz

Table I.3 DYN-X SIMULATION SUMMARY

- *Note: Qgas is the maximum rate possible given the input wellbore geometry, as calculated from DYN-X runs.
- *Note: Negative pump pressure means that the relief well will go on a vacuum when interception is made.

The wellbore geometry along with the contract drilling equipment was modelled in a frictional model. Pressure loss equations were per Preston L. Moore "Drilling Practices where Fann data is used to determine friction at a fluid shear rate. Flowing bottom hole pressures were taken from the computer models described earlier. The kill rate plus a percentage to account for leak off was modelled for flow down the relief well annulus, with the drillpipe held for pressure observations. The design horsepower requirements have a 1.5 safety factor applied. Note that the rates used in the frictional model were increased 10% for leak off. Therefore the gross factor of safety for horsepower is 1.65 times the theoretical values. This safety factor is reasonable when considerations are given to unknown factors, like equipment failures etc. The horsepower requirements are summarized in Table I.3.

The volume anticipated for the kill operation is two hole volumes of the blowout well or about 1500 barrels. This was determined from the computer model and experience. Note that if a relief well is drilled, a transient analysis, DYN-XT, will be needed to refine the pumping requirements for the kill operation. This was not done in this report because it was not part of the scope of work and not necessary.

10.9.11 Equipment Specifications

For safety and reliability, it is recommended that the external pumps (DS Schlumberger, BJ, etc.) be provided in all cases. For purposes of discussion in this report Halliburton pump specifications shall be used (not as a recommended vendor for these services, but because the author is more

familiar with this equipment than others). If a vendor other than Halliburton is chosen, their equipment will be comparable and little modification necessary except a review of pump-volume characteristics.

To follow the kill procedures, and in particular to maintain control of bottom hole pressure in all downhole conditions and in all-weather environments, a surface pumping spread per Figure I.10 will be necessary. Table I.3 shows the maximum recommended pumping spread where 10 each 612 HP pumps are provided. The lesser cases will require fewer pumps, but all the supporting booster pumps and holding tanks will remain the same.

Having a stimulation vessel provide the pumping requirements was considered; at first, it seemed to be a viable choice. However, upon review, certain factors ruled out the stimulation vessel as the primary pumping source. The major reasons were availability and possible conflicts with existing long term contracts with other area operators. The main reason is that these vessels are not equipped to handle a weighted fluid for extended periods of time. For safety reasons, the overall plan calls for kill weight fluid to be on standby ready to pump at a moment's notice. Thus the kill operation must be rigged up and kept on 24 hour notice during all of Phase III drilling. To use a stimulation vessel to provide pumping capacity, kill fluids must be transferred to the vessel on the fly making a complex hook up for both suction and discharge requirements. This cannot be considered 100% reliable in all weather and light conditions. Therefore installation of all pumping equipment on the main deck of the drilling rig is the most viable option.

Mixing

Mixing of the kill mud will be done by the drilling rig. The kill fluid should be transferred to 500 barrel top deck storage tanks sea fastened to the main deck of the drilling rig.

Suction Supply

Booster pumps will provide suction pressure for the high pressure pumping spread. These booster pumps shall feed into a 6" discharge ring that is fully manifolded to feed the high pressure pumps and return fluid to the pit area for conditioning if required. A tie in for a supply boat transfer of mud shall also be provided. A fluid transfer system shall also be supplied to move mud from the pit room to the main deck at 10 bpm rates. The booster system and/or the high\ pressure pumps shall be used to roll the fluid in the deck holding tanks, thereby assisting in maintenance of rheological properties. Densometers and flowmeters shall be installed at convenient locations in the suction supply system.

Discharge System

A 3" 10M working pressure distribution manifold will connect all high pressure pumps to a central manifold connected to the kill and choke line of the drilling rig. The central manifold shall have provisions for a tie to a stimulation boat, high volume return line to the holding tanks (for testing the system) and a relief-dump line overboard. Check valves will be required on the lines that connect the choke and kill lines. Tie in to the kill lines shall be in the moon pool area, bypassing the standpipe and choke manifold. Both high pressure and volume pumping will be required of this system.

Pumping Equipment

The pumping equipment shall be high pressure fracture treatment pumps. They shall be skid mounted in a protective frame acceptable to offshore operations. Due to limited deck space these frames must be so configured that it is permissible to stack the pump on top of one another. They shall be independently driven by diesel powered engines with normal controls, spark arrestors, and air shut offs. Discharge pressure shall be 10,000 psi working pressure. For pump unit calculation the capacity of a Halliburton HT-400 pump (4-1/2" liner with 8 inch stroke) powered by a GM Diesel 16V92 with 612 input horsepower is used. The pump pressure relationship, pressure volume

curve, has been used as supplied by Halliburton, Duncan, Oklahoma. This particular PVC is shown in Fig. I.9

Rather than applying a multitude of factors to each of the inputs to the pumping requirement. The author has chosen to use the maximum values and then apply an overall safety factor, therefore when predicting the number of pumping units required the calculated discharge pressure determines maximum unit discharge rather than applying factors of safety to each individual parameter.

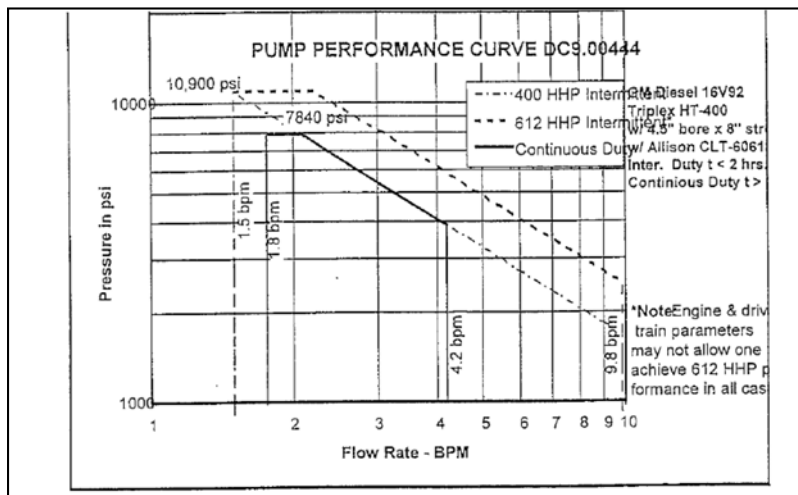


Figure I.9 Pressure Volume Curve

(Courtesy of Halliburton Energy Services, Duncan, OK)

The basis for calculating the required pumps follows:

$$N_p = Q_k / (1 - LO) \times SF / Q_m$$

Where :

N_p = number of pump units (round to integer)

Q_k = design kill rate, (bpm)

SF = safety factory (*)

LO = per cent leak off in decimal form, (*)

Q_m = max flow per unit, (bpm per unit) from manufacturer's data for 100% performance at anticipated discharge pressure, P_m

Example: For a given Scenario, the maximum discharge from the pressure loss model is 1600 psi (rounded to nearest 100 psi). From Figure C.9 the PVC discharge yields maximum available rate per unit, Q_m of 10.0 barrels per minute per unit if maximum horse power is expended. Assuming 10% leak off to the formation during the kill operation, LO becomes 0.10. The recommended overall safety factor, SF , is 1.50. Thus for this scenario the required number of pumps will be:

$$N_p = 47.52 \times 1.5 / (1 - 0.1) \times 10 = 7.92 \text{ or } 8 \text{ rounded up.}$$

Table I.3 presents the design conditions for pumping units if Halliburton HT-400 16V92 powered units with 4-1/2" liners (162 max hp each unit) are chosen as the primary pump unit.

Control System

Control of all high pressure pumps shall be by remote control from a single unit so that one person can control all the pumps in the spread. Constant communication with the command center

(computer skid) shall be necessary. Pump and bottom hole pressure as well as volume pumped shall be electronically recorded. Digital displays of discharge pressure, cumulative pumping rate, density of discharge fluid and cumulative volume shall be displayed. The control and recording devices shall be housed in a single module that has space for the pumping vendor technicians as well as 4 company's representatives.

Safety System

Safety systems shall be provided so that the technicians can monitor:

- critical engine functions on pumps and boosters
- fluid levels in holding tanks
- communications from rig command center
- Bottom hole pressure and temperature from a surface read out wireline conveyed pressure gauges located in the relief well.

A relief valve in the overboard line shall be installed. This shall have automatic reset. Check valves shall be installed in the discharge line and at critical points in the discharge piping system.

Testing / Training

Testing of the pumping system should be done with sea water and with weighted fluid. The discharge system has a return and overboard line for this purpose. The pumping of 2000 barrels should take less than one hour at design rates; however the final stages of the kill may have very low rates. Therefore the pumps should be tested to see that they can deliver the design rate and horsepower (with safety factor) by pumping against a choke with sea water for 30 minutes at 3300 psi. Intermittent (10 minutes) pump test at 7,000 psi with all pumps on line will test that all available horsepower can be delivered through a range of working pressures. This will ensure flexibility of the operation should it become necessary to alter the job specifications.

A weighted fluid pumping test should be performed to insure that the suction and discharge systems provided are adequate at the design rates. The actual frictional losses in the system from the discharge, deck lines, manifolding and kill line to the BOP should be determined by circulation. This test should be done with weighted fluid and with sea water while waiting on cement after setting 9-5/8" casing or earlier if possible.

An important aspect of the kill procedure will be the coordination of all service company personnel and company representative. It will be critical that information flow freely to the onsite management team. The trial runs to test the pumping system should include a full test of all monitoring systems and personnel involved.

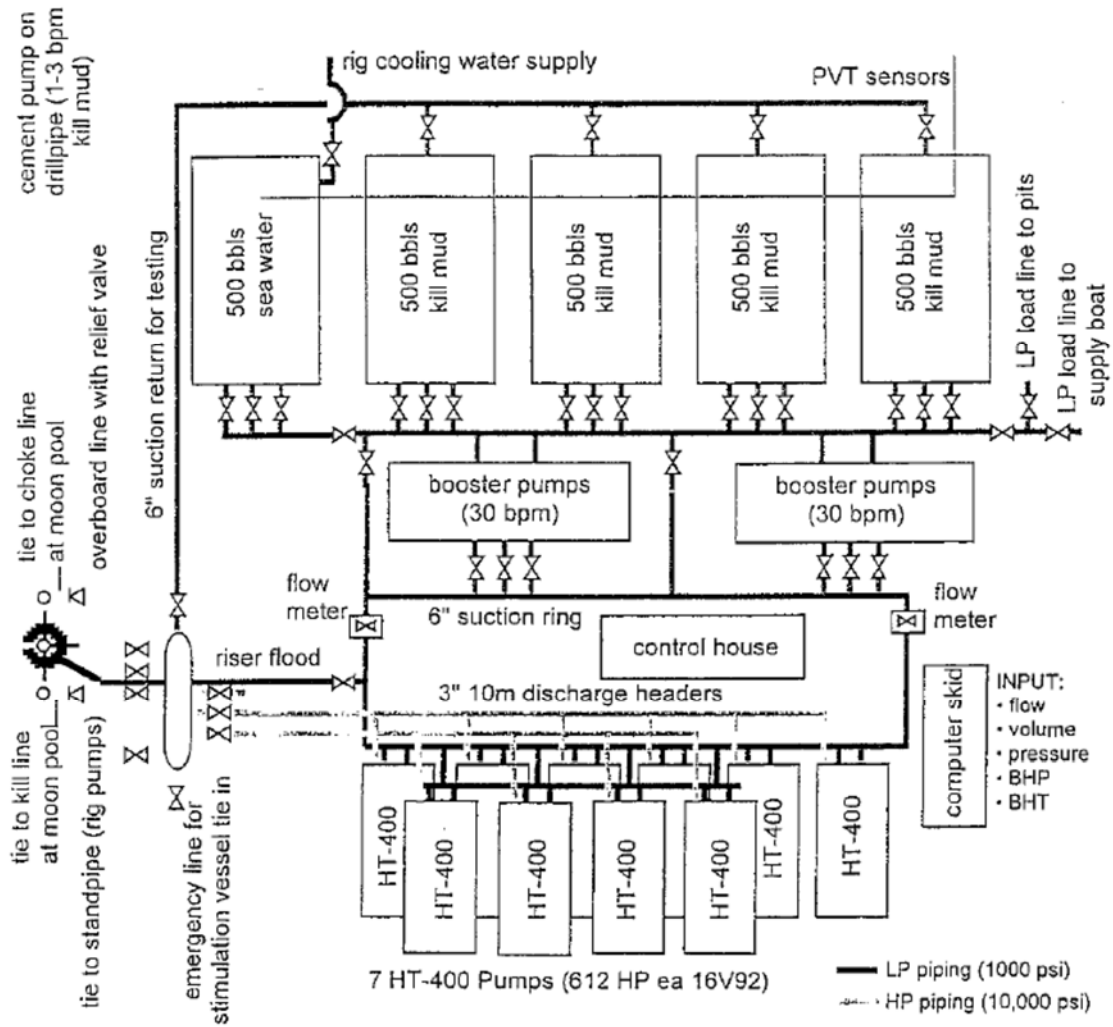


Figure I-10

10.10 SURFACE CONTROL SPECIAL SERVICES

10.10.1 Hot Tapping and Valve Drilling

Hot tapping and valve drilling equipment has been used on blowouts to allow pumping into wellheads, tubulars or fire frozen valves. This equipment is available from most major blowout specialist companies as part of their service capabilities.

In a hot tap, a saddle clamp is installed around the tubular and a pack off is energized. Within the lubricator a drill bit cuts through the tubular with pressure held slightly higher on the outside than on the inside so positive indication that a hole has been made is seen. After the hole is cut, it can be reamed out up to 1". Valve drilling machines are available to drill out frozen gates. Up to 3" holes have been drilled with larger hole sizes milled out.

These services are available from Boots & Coots, Cudd, Halliburton, HWC and others. Pipeline companies use hot tap equipment and may be adaptable to certain applications. Saddle clamp sizes should be investigated. A specialist should be utilized in any case for safety.

10.10.2 Freezing

Freezing is used to place an ice plug within shut in wells (within pipe, wellheads or annulus) to allow removal, repairs or replacement of wellhead equipment. Freezing has not been used to control a high volume blowing well.

Some inventors attempted to market devices using liquid nitrogen to freeze off blowing wells in Kuwait, but simpler control methods were available. Difficulties were seen in maintaining the freeze plug of frozen oil and brine while making extensive surface repairs to blown up wellhead equipment.

Freezing techniques usually use dry ice to freeze water or fresh water-bentonite slurries. Methanol can be used with dry ice to get a lower temperature. A 75% methanol/water mixture has a freeze temperature of <-200° F. Methanol water mixtures could be potentially cooled by liquid nitrogen and the cold methanol/water mixture circulated around the area to be frozen.

This would allow control of the applied temperature to the steel. Problems with low fracture toughness in super cooled steels have been observed in nitrogen pumping service when pump rates exceeded heater capabilities and liquid nitrogen was pumped into wells.

Freezing services are available from Boots & Coots, Cudd, Halliburton, HWC and others.

10.10.3 Pneumatic Casing Cutters

Pneumatic cold cutters are used to strip away outer casing strings to expose inner casing strings for well capping. ABB Vetco Gray has equipment available to make vertical stripping cuts to split casing strings. The pneumatic cold cutters are commonly used in the pipeline business. Common sources are ABB Vetco Gray, Boots & Coots, Enterra Wellcat, Porta-lathe and others.

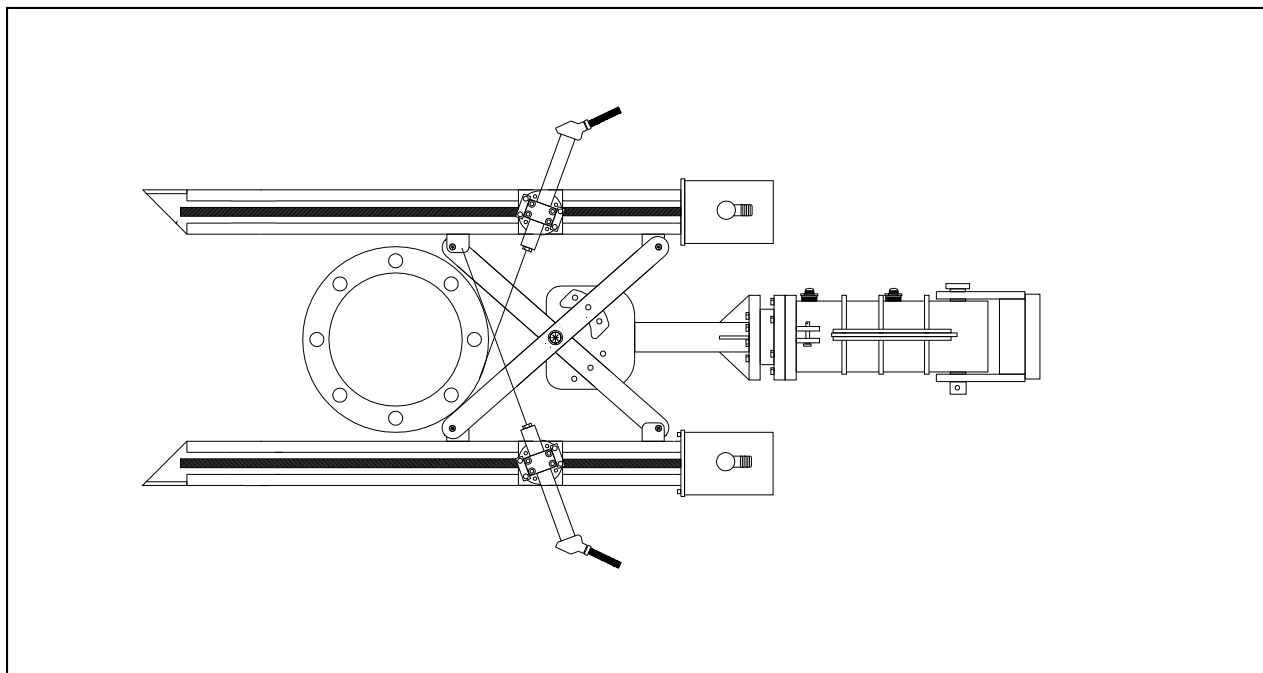
10.10.4 Abrasive Jet Cutters

The Halliburton abrasive jet cutter was developed to deal with the aftermath of the Arabian Gulf War. Because of the extensive number of wells that were burning, Halliburton developed a way to rig up quickly, cut from a remote location and rig down quickly to move to another well. This cutter was designed to cut the casing below the braden head, which cuts all the casing strings, cement between casing strings and tubing in the center.

The abrasive jet cutter incorporates two jet nozzles opposing each other. A hydraulic motor turns a linear screw that moves the nozzles either in a forward or reverse direction. The cutter is positioned on each side of the wellhead and pressure from the pumping equipment is established

at 10,000 psi at approximately 4 bbls/min. Sand is added to the blender and the sand slurry is delivered to each nozzle. The nozzles are then tracked forward cutting everything between the two nozzles.

All hydraulic lines are encased in a water jacket due to the intense radiant heat associated with a blowout. Also as an added feature the cutter can be rotated clockwise to counter-clockwise and raised up or down. This simplifies trying to cut on a leaning or damaged wellhead.



This is controlled by a small hydraulic power pack that is incorporated into the skid that houses the cutter during shipping. This power pack and control system can be placed up to 250 feet from the actual cutter assembly. From this safe distance the well control specialist can control the movement of the cutting jets.

The abrasive jet cutter has cut a forty eight inch diameter flange the largest to date. The average cut usually made with the cutter is between twenty four inches to eighteen inches in diameter. With a cutting pressure of 10,000 psi, a pump rate of four barrels per minute and a pound per gallon sand concentration the cutting time is less than one hour for these applications.

10.10.5 Requirements for the Halliburton Abrasive Jet Cutter

- Two thousand hydraulic horsepower (2,000 hhp) – that has been horsepower tested for at least twenty minutes at 10,000 psi and 4 bbls/min. If 2,000 hhp is not available, contact Halliburton Well Control in Duncan.
- Pumping iron – This depends on each individual blowout location. Usually five hundred feet of straight two inch 1502 with an assortment of style 50 angle wing chiksans and tees to wye the pumping equipment together. Suction hoses to hook up pumps.
- Sand Requirements – 20/40 Ottawa frac sand is preferred but 20/40 Brady, 20/40 inter-prop or 20/40 bauxite can be used if the Ottawa is not available. Amount per hour of cutting = 12,500 pounds.

Halliburton Well Control will supply the blender and in most cases a centrifugal pump to mix the sand and water together.

10.10.6 Explosive Jet Cutter

Shaped charges can be made in the field using raw C4 plastic explosive in fabricated holders. Point cuts, linear cuts and circular cuts can be fabricated by firefighting explosive experts. Manufactured cutting charges are stocked by explosive manufacturers in some regions, but cannot be custom configured to the application. These are generally the same companies that make oil well perforating charges (GOEX and JRC).

10.10.7 Hydraulic Simulator

Hydraulic modelling software and specialists will be required to help perform blowout scenario diagnostics and kill simulations.

Planning the kill strategy for a 1989 underground blowout in the North Sea required development of an improved flow simulator. The hydraulic kill simulator was based on the industry standard, two phase pipe flow model, OLGA. After the project, the planning team realized that they gained considerable advantage from using a transient two phase flow simulator for comparing various kill scenarios. Since then, the OLGA-WELL-KILL simulator has been used successfully for a number of intervention design plans.

The ability to analyse hydraulic kill scenarios quickly and find their effect on the rest of the intervention operation is critical to project success. A specialized need was therefore identified for a multiphase, time transient, flow simulator designed for easy blowout kill analysis. This need was the driver that motivated the continued modification of the pipeline code for well flow and kill simulations.

During a blowout kill, up to six fluids can be present simultaneously in the well reservoir; oil, gas and water; kill water, intermediate and final kill mud. Conventional kill models cannot easily evaluate multiphase flow where heavy kill muds are used.

Simulations handle this by first simulating the dynamics of a liquid/gas biphasic flow regime, then comparing this to a simulation using averaged properties in a light weight liquid phase. The kill phase is then introduced and a dynamic two phase simulation is performed until a steady state condition is reached. Afterwards, the next phase can be introduced and the simulations can be restarted at any time.

Modelling is accomplished using a number of controllers set to contain the simulation within the physical constraint of the real blowout. The controllers can, for example, be set on the following parameters:

- Pump rate.
- Pump horsepower.
- Formation collapse pressure.
- Casing burst pressure.
- Surface injection pressure.
- Bottom hole pressure (min/max).
- The simulation modeling includes
 - Pump performance
 - Non-Newtonian fluid flow (for mud)
 - Fluid temperature and pressure response
 - Inflow modelling (multiple if needed)
 - Leaks (multiple if needed)
 - Back pressure (outflow conditions)

- Several reservoir inflow models
- Variable reservoir pressure
- Path chokes (critical and sub critical)

In practical use, the modelling is usually taken through a number of steps starting with a PVT fluid characterization of the reservoir fluids. The blowout is then modelled to match all available data.

The next step is to set up a constant rate kill simulation to work out the range for the simulation of the actual dynamic kill. This is also useful in evaluating allowance for losses between wells (for relief well kills) as well as for the kill fluid density, and for velocity and pressures at critical points in the blowout path. The fully dynamic simulations can then incorporate all the actual constraints in the kill such as casing pressure ratings, fracture pressures, inflow performance and reservoir pressure (dynamically versus time, if necessary), pumping plant and mud properties.

The simulation yields an actual pump schedule vs. time (with rates and pressures at any chosen point in the flow path). If needed, a number of sensitivities can be developed to evaluate kill effectiveness during the actual pumping. This later step can often prove useful when there are unknowns in the kill (such as communication between relief well and blowout well, actual blowout flow path or reservoir performance.)

Applications include the following:

- Kill with different mud densities in the well.
- Partial losses during kill.
- Multiple blowout paths, cross flows and leaks.
- Multiple relief wells pumping at different rates.
- Underground blowouts from a drilling rig.
- Simultaneous bullheading and dynamic kill.
- Off bottom or momentum kills, shallow gas blowouts.
- Horizontal well flow analysis.
- Slugging in long reach production wells.
- Rates required to circulate out a kick in horizontal wells.
- Alternating gas and water injection.
- Sensitivity analysis by varying parameters.

10.11 EMERGENCY CONTACT LISTS

Refer to current contact lists provided by the various department managers.

Use this link to find everyone in the oil field

<https://www.oildex.com/resources/directory/>