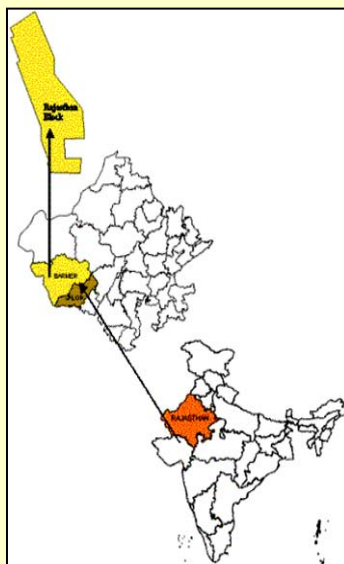
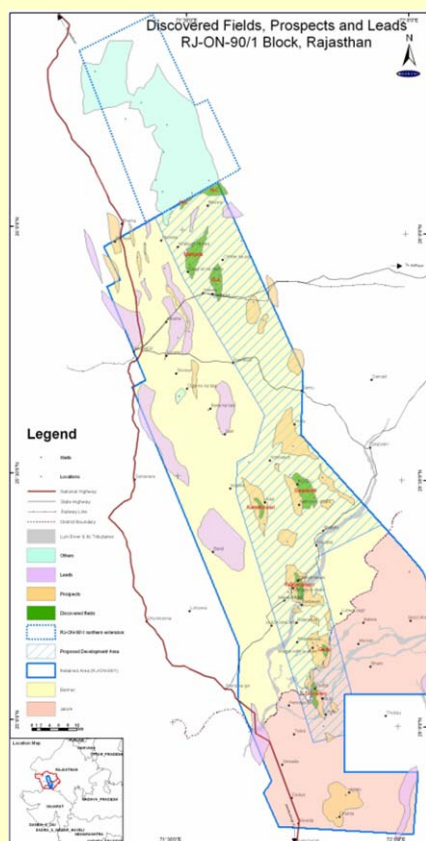


Risk Assessment for Hydrocarbon Development in RJ-ON-90/1 Block in Barmer District, Rajasthan (Mangala, NA-1, Saraswati & Raageshwari Fields)

Sponsor



Cairn Energy India Pty Ltd., Chennai



National Environmental Engineering Research Institute
Nehru Marg, Nagpur 440 020

December 2004

Rapid Risk Assessment for RJ-ON-90 / 1 Onshore Block in Rajasthan State

Sponsor



Cairn Energy India Pty. Ltd., Chennai



**National Environmental Engineering Research Institute
Nehru Marg, Nagpur 440 020**

December 2004

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Chapter 1

Introduction

1.1 Preamble

The Government of India has awarded Petroleum Exploration License under the Production Sharing Contract (PSC) for RJ-ON-90/1 onshore block in Rajasthan State to Cairn Energy India Limited (CEIL). The RJ-ON-90/1 block is located in Barmer and Jalore districts of south-western Rajasthan. CEIL has been conducting exploration activities within the block for the past eight years and discovered several commercially viable hydrocarbon reserves in the block. The current area of the block is approximately 5820 km² and lies between 24°47'7.58" to 26°26'00.99" N latitude and 71°15'41.17" to 72°4'39.29" E longitudes. The block boundaries are shown in **Fig. 1.1**. CEIL is in the process of planning the development of these hydrocarbon discoveries.

CEIL has drilled several exploratory wells in the block and has been carrying out extensive seismic surveys to delineate the extent of the various hydrocarbon reserves and have made several hydrocarbon discoveries in the RJ-ON-90/1 block. They are Guda (1999), Saraswati (2001), Raageshwari (2003), Kaameshwari (2003), GR-F (2003), Mangala (2004), Aishwariya (2004) & Shakti (2004).

CEIL proposes to develop the Northern zone fields namely Mangala and Aishwariya, and Central zone namely Saraswati, and Raageshwari oil fields and the Raageshwari gas field. All the fields are planned to be developed concurrently and are expected to be completed by October 2007.

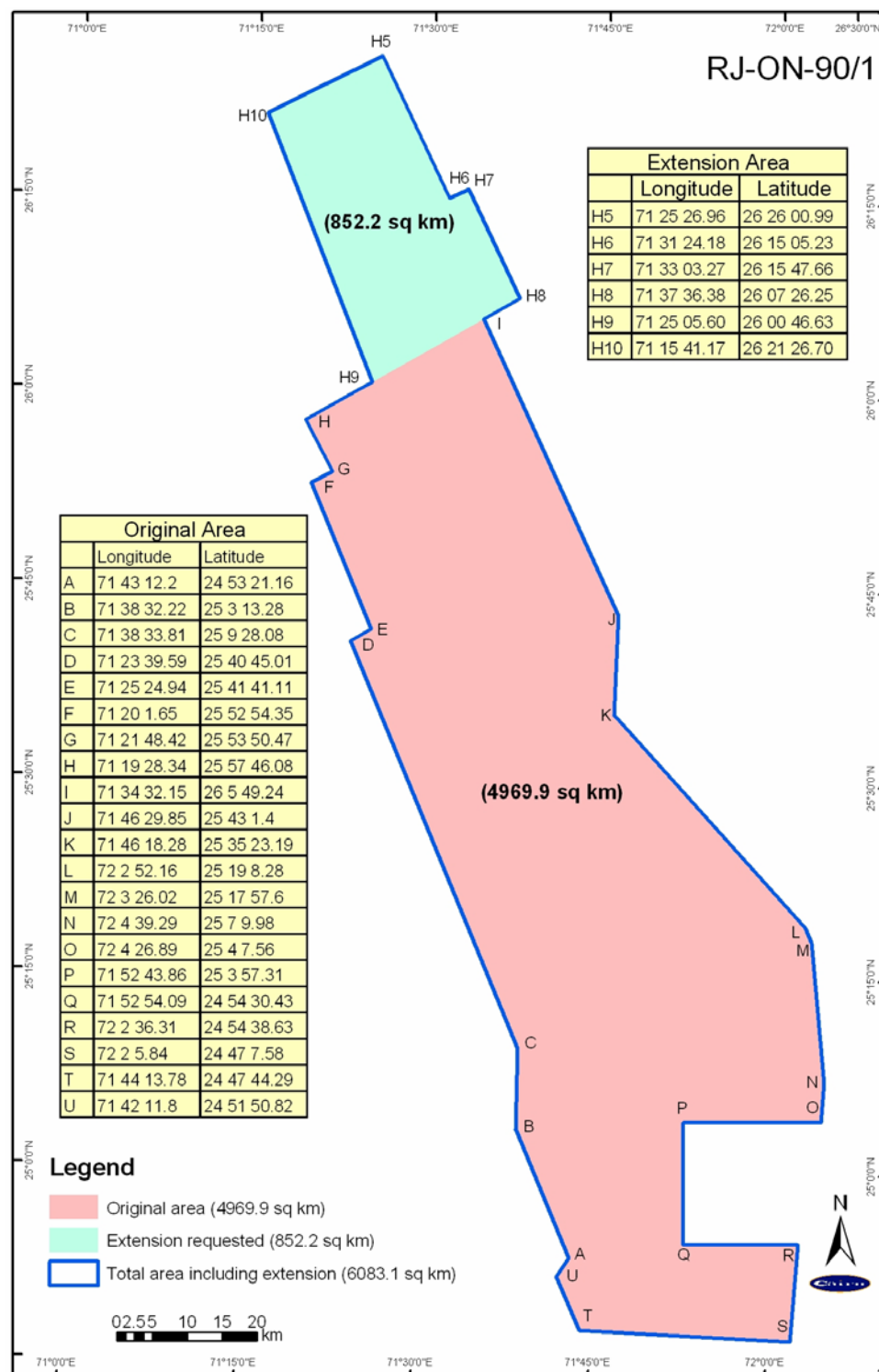


Fig. 1.1: RJ-ON-90/1 Block Boundaries

CEIL has retained **National Environmental Engineering Research Institute (NEERI)** to carryout **Risk Assessment (RA)** study for the proposed developments..

1.2 Proposed Development Plans

It is proposed to develop the following five fields in the block and the capacities of various field developments are presented below in **Table 1.1**.

Table 1.1
Capacities of Field Developments

Field	Max. No. of Wells Pads	Max. No. of wells	Total Crude Oil Production (BOPD)	Total Gas Production (MMSCFD)
Mangala Field development	15	Production wells – 195 Injection Wells – 195	1,00,000	17
Aishwariya Field development	8	Production wells – 40 Injection Wells – 40	20,000	3.4
Saraswati Field development	4	Production wells – 24	6,000	0.07
Raageshwari Field development	6	Production Wells – 36	2,000	0.28
Raageswari Gas Field	2	Production wells – 8	-	20

The salient features of the development plan are:

- ◆ The plan will cover the development of the Mangala, Aishwariya, Saraswathi, Raageshwari Oil fields and the Raageshwari Gas field. **All the above fields and the planned facilities are located within Barmer district, Rajasthan**
- ◆ A total of 303 hydrocarbon production wells and 235 injection wells are proposed to be drilled
- ◆ The total aggregate production from these fields will be 128,000 barrels of oil per day
- ◆ Cumulative production of associated gas at rates up to 30 Million Standard Cubic Feet Per Day (MMSCFD) from the 4 fields
- ◆ The Raageswari Gas field will produce upto 20 Million Standard Cubic Feet Per Day (MMSCFD)
- ◆ Captive Power Plant of 50 MW power generation capacity will be established and operated at a central location to meet the energy requirements of Mangala

& Aishwariya field development. The power plant would use crude oil or natural gas or both as fuel source

- ◆ It is estimated upto a maximum of 25,000 m³/day of saline water would be required to enhance oil recovery. Saline water well field identified approximately 9 km south of the Aishwariya field development area will be developed to source saline groundwater required for injection into the oil reservoir of Mangala and Aishwariya field. The saline water will be conveyed through pipeline network to the CPF for co-mingling with the produced water and injection will be done through a network of dedicated injection wells
- ◆ The freshwater requirements for the oil facility process, domestic and greenbelt requirement will be met by desalinating the saline groundwater. The desalination reject water will be combined with the injection water
- ◆ The development concept will be based on modular design. Each module will start with a number of well pads or sites from which a single / multi flow line will carry the 3-phase well fluid to a Group Gathering Station (GGS) where the well fluids will be processed and the stabilized crude oil will be stored in storage tanks / or routed to one or more Central Tank Farms (CTF) for export
- ◆ The tentative locations of the production, injection wells, group gathering stations (phase separation facilities), infill pipeline / export pipeline routing and CTF has been finalised, however specific location will be decided based on land availability. **It is therefore expected that the final well pad locations may be within 1 km radius of the indicated locations.** There are two alternate locations shown for the GGS & CTF and the final location will be any one of the two. **The GGS, CPF & CTF may be within 500 m radius of the given locations**
- ◆ The hydrocarbon discoveries made in the RJ-ON-90/1 block are crude with high wax content in varying quantities. Thus the process of abstraction, pumping and processing will include several options including heat treatment, partial refining and chemical dosing
- ◆ The development strategy assumes that early production from some of the low producing fields will be trucked until the export pipeline arrangements have been implemented. Oil will be sold to Indian Oil Corporation (IOC), the buyer nominated by the Government of India (GOI). Additionally there could be

internal trucking of crude within the block from the smaller discoveries to loading points, from where it will be transported through pipelines

- ◆ The produced water generated from fluid separation will be treated and treatment facilities of varying capacities (depending on the field production rates) would be set up at several locations and the treated produced water will be mingled with the external injection water and reinjected into the oil reservoir. The total quantity of reinjection water would be 380,000 barrels per day (~ 60,500 m³/day)
- ◆ The GGS shall be placed within the vicinity (located within radius of 1-3 km) of well pads
- ◆ There would be a network of pipelines connecting well pads, GGS, Central Processing Facility (CPF) and Central Tank Farm (CTF) for carrying well fluids, produced water, lift gas, fuel gas, stabilised oil, injection water, lift gas, hot oil, etc. The size of pipelines would vary from field to field.

1.3 Project Cost & Schedule

The development cost over the field life is presently estimated to be between US\$ 560 million to 850 million (Rs 2,520 Crores to 3,825 Crores), depending on the field configuration that would be selected based on the results of the sub-surface investigation and the Front-End-Engineering-Design (FEED) Study.

CEIL proposes to develop all the five fields concurrently and the entire project is expected to be completed and **production to commence by October 2007**. Since the amount of work required for developing the southern fields are comparatively less, CEIL may bring the Saraswati & Raageswari oil fields into early **production by April 2006**.

1.4 Project Setting

The current block area of RJ-ON-90/1 block is approximately 5820 km². The proposed development project is located within five identified pockets within the block area. The block lies between 24°47'7.58" to 26°26'00.99" N latitude and 71°15'41.17" to 72°4'39.29" E longitudes. The block is located in Barmer and Jalore districts of south-western Rajasthan i.e. within the Indian Thar. It covers parts of Baitu, Barmer and Guda Malani tehsil in Barmer district and Sanchor and Bagoda in Jalore district.

The proposed development fields **are entirely located in Barmer district in the Baytoo, Barmer & Gudha Malani tehsil.**

1.5 Weather Conditions

The long term analysis of micro-meteorological conditions of Barmer district based on the last 30 years data has been carried out for the post-monsoon, winter and summer seasons. In this analysis, September-October, December-January-February and April-May-June are considered to be representative of post-monsoon, winter and summer seasons respectively.

Based on 1951 to 1980 climatological data, the minimum annual mean temperature in Barmer district is 6.3°C and maximum annual mean temperature is 45.8°C. The extreme temperature ranged from –1.7 to 48.9°C in the given period. The relative humidity ranged from 31% to 74%, 27% to 53% and 23% to 67% in post monsoon, winter and summer season respectively. The cloud cover is observed to be in the range of 1.3 to 2.4 oktas. The annual rainfall in last 30 years is recorded to be 262.9 mm. The predominant wind direction switches over from N-W/N-E sector to S-W sector.

1.6 Topography

Apart from a small offshoot of the Aravalli hills in the east, the area is a vast sand covered tract with substratum of gneiss, hornblende and quartz, which at some locations rise up through the sand, in some instances to a height of about 243 to 304 meter. The only river of this region is the Luni (salt river), which rises about 7 km north of Ajmer in the Aravalli ranges and passes through the Pachpadra and Guda-Malani tehsils of Barmer and Sanchor tehsil of Jalore divisions. It flows for 482 km before draining into the Arabian Sea at the Rann of Kutch in Gujarat. The Luni river is seasonal and comparatively shallow, although at places it is over 2 km wide. Its main tributaries are the Lilri, Raipur sukri, Bandi, Mitri, Jawai Khari, Sagi and Johari which all rises in the Aravalli. Almost half of the RJ-ON-90/1 region falls in the Luni river basin. The area remains dry throughout the year except for few days rain during July-September.

This region is the largest producer of bentonite which is used as grouting material in engineering construction, in drilling mud and in insecticide, paint, pharmaceutical, vegetable oil and petroleum industries. The important minerals produced in this district are bentonite, gypsum, silicious earth and salt yielding good annual revenue. Gypsum deposits are located at Phulsund, Kawas and Utarlai and is used in the manufacture of fertilizer, plaster of paris, distemper and cement.

1.7 Infrastructure Resource Base

1.7.1 Electricity

The power supply in the district comes from Debari Grid Station near Udaipur via Jalore. The 132 KV Grid Station of the district is located at Balotra and the 33 KV station is located at Barmer. Of the 1,625 villages, 1,500 villages are electrified.

1.7.2 Water

The block lies in primarily arid and semi arid zone with vast areas of sand covered tracts on bedrock of gneiss and sedimentary depositions. The entire stretch of the block is covered by sandy soils with golden colored sandy dunes. The depth of groundwater in the development area ranges between 75 – 100 m. The aquifers in the study area are mostly brackish with pockets of sweet water in confined and unconfined aquifers.

This is an inter-State project shared by Gujarat and Rajasthan, the storage reservoir known as Sardar Sarovar Dam is located in Gujarat, where the Narmada Canal starts, and after traversing 458 km in Gujarat enters Rajasthan near Silu village in Sanchores Tehsil of Jalor District. The project is designed to supply 616 million cubic meters per year of irrigation water to Barmer & Jalore district in Rajasthan, and provide drinking water to 124 villages in Barmer and Jalore Districts, covering a target population of 3,50,000. The project is expected to be completed by 2007. The total length of main canal in Rajasthan will be 74 km and total length of distributaries will be 1403 km. in Jalore & Barmer districts irrigating 130 km of command area

The Indira Gandhi canal is being extended upto Gadra Road in the district. This is likely to provide adequate quantity of not only drinking water but also to irrigate about 0.1 million hectares of agriculture land. The flow of the canal would also improve water level of the wells in the area covered by the flow. The canal extension project is expected to be completed within the next 3 to 4 years

1.7.3 Road Transport

The district is linked by road with Jaisalmer, Jodhpur, Pali, Jalore, Jaipur, Ajmer and Ahmedabad. The total length of roads in the district was 5,109 kms as on 31 March 2000. Major Roads within the block are NH-15 (58.89 kms), NH-112 (33.28 kms), SH-16 (43.0 kms) SH-28 (54.37 kms); these roads add up to a total length of 189.5 kms.

Most revenue villages in the Gram Panchayats do not have any motorable road. Only kutchha roads or pathways exist, which keep shifting due to movement of sand. 30% of

the revenue villages, were approachable only through kutchha roads. More than 92% of the villages do not have any internal village roads or have only kutchha pathways. There is only limited public transport facility in the area and this too is mainly confined to the areas along the main roads / highways.

1.7.4 Rail Transport

The district is linked with neighbouring districts of Jodhpur, Jalore and Jaipur in the State and with Agra in UP and Munawa in Pakistan, by railway line. The total length of rail line in the district is 254 kms with 30 railway stations. The Northern Railway Main Line passes through the block, the total length of the line within the block is 36.55 kms. There are regular railway services connecting Barmer to Jodhpur, Jaipur and Delhi.

1.7.5 Air Transport

The nearest airport is at Jodhpur located about 220 km from Barmer.

1.7.6 Defence Establishment

Uttarlai, one of the forward airbases of South Western Air Command, is located 10 km from Barmer. There is a BSF (Border Security Force) campus contiguous with the urban area boundaries of Barmer town.

1.7.7 Communication Facilities

There is regular postal and telecommunication services connecting the various town and villages of Barmer district to the rest of the country. There are 479 post offices, 104 telegraph offices, 64 telephone exchanges and 894 public call offices

1.7.8 Industrial Scenario

There are no significant industrial activities or industrial area falling within the project area and the nearest industrial area is Balotra, which is about 100-km northeast from the centre of the block. Some isolated mining activities, machining works, gypsum manufacture, small-scale textile dying and printing, leather products manufacture, brick kilns, bentonite grinding, cement bricks manufacture, embroidery and tailoring, flour mills, granite cutting and polishing, guar gum, non-edible oil, oil mills, plaster of Paris, stone crushing, wooden furniture manufacturing are carried out. There are five industrial areas in Barmer district with about 3000 small-scale units.

The export items are Gaur gum, handicraft, hand-embroidered items and woollen carpets.

1.7.9 Major Crops and Their Production

In Barmer, generally some kharif (summer) crops are grown with well water. Common kharif crops are bajra, jowar, maize, pulses and oilseeds. Rabi crops are also sown when Luni river floods. The main rabi crops are wheat, with gram and barley in some areas.

1.7.10 Minerals

Barmer district is rich in mineral deposits such as lignite, gypsum, saliceous earth, salenite masonry stone, bentonite and limestone.

1.7.11 Risk Assessment

With a view to assess the environmental impacts arising due to the proposed development plan in the RJ-ON-90/1, Rajasthan, CEIL retained the **National Environmental Engineering Research Institute (NEERI), Nagpur** to prepare an Risk Assessment (RA) Report.

1.8 Objectives of Risk Assessment Study

The objectives of the Risk Assessment are as follows:

- ◆ Identification of vulnerable zones in the drilling area, oil and gas processing facility, CTF, Power plant and along the pipeline
- ◆ Estimation of hazard distances for the Maximum Credible Accident scenarios
- ◆ Failure Frequency Analysis
- ◆ Risk Assessment

Suggestions for risk mitigation measures and delineation of Approach to Disaster Management Plan (DMP)

1.9 Scope of Work

The scope of the present report is to carry out risk assessment of the wells, oil and gas transportation pipelines, Gas Processing Facility, CTF and Power plant. Standard industry practices of risk assessment are considered in the project. Maximum Credible Accident analysis is carried out to arrive at the hazard distance for the worst case scenario. The consequences of all the scenarios are computed and hazard distances are worked out and listed for flammable materials and possible explosion effects.

The work undertaken consists of the following stages:

- ◆ Collection of relevant data on wells and other facilities
- ◆ Damage distance computations
- ◆ Failure Frequency Analysis
- ◆ Risk Assessment

Risk mitigation measures, based on MCA analysis and Risk analysis and engineering judgements.

Chapter 2

Project Description

2.1 Project Background

The RJ-ON-90/1 Production Sharing Contract was executed between the Government of India, ONGC and Shell India Production and Development (SIPD) on 15th May 1995. The Contract Area covered was approximately 11,108km². CEIL farmed into the block in three stages, initially taking a 10% interest from SIPD in 1997 and increasing that interest to 50% in further stages in 1998 and 1999. In 2003 Cairn Energy Hydrocarbons Ltd (CEHL) acquired SIPD's equity in the block and the Contractor under the PSC is now constituted of ONGC, CEIL and CEHL. CEIL and CEHL are wholly owned subsidiaries of Cairn Energy PLC. The Government of India (GoI) extended the Exploration Period for a period of three years, from 15th May 2002 to 14th May 2005. Following the relinquishments at the end of PSC Exploration Phases I, II and III the Contract Area comprised of 4970km². The Government Of India (GoI) – Ministry of Petroleum & Gas (MoPG) accorded approval in July 2004 for the extension of the Phase-III block retention area by 852 km² to carry out exploratory drilling to the north of the Shakti oil discovery well. The current total area of the block is about 5820 km².

CEIL participated with Shell (as operator) in the drilling of the onshore Guda-1 and Guda-2 wells, in the block in early 1999. The Guda-2 oil discovery was drilled on this structural trend. In November 2001, CEIL made a second oil discovery on the block with an exploration well on Prospect-H (Saraswati) located towards the basin flank. In February 2003, CEIL announced discovery of oil and gas from the exploratory well drilled in the

Prospect-E, near village Nagarka in Barmer district and now called the “Rageshwari Field”. This was followed by the discovery of the Kaameshwari field and the GR-F field.

CEIL has drilled about 40 exploratory and appraisal wells in the block and has carried out extensive 2D over ~ 6000 line km & 3D over 1000 km² seismic surveys to identify leads and prospects, explore and delineate the extent of the various hydrocarbon reserves of the hydrocarbon discoveries and to better understand the intricacies of the complex structures within the discovered fields in the RJ-ON-90/1 block so as to provide adequate information to prepare an appropriate hydrocarbon production development plan.

2.2 Recent Development

CEIL persistence and aggressive exploration policy yielded phenomenal success when from the beginning of 2004 significant hydrocarbon discoveries have been made in the northern portion of the block. A discovery was made in the N-B prospect (Mangala Field near village Jogassaria, (Baytoo tehsil) in early January 2004. This was followed by the find in the Aishwariya prospect (Aishwariya Field near village Kawas, (Baytoo tehsil) in March 2004, discovery in the Shakti prospect (Shakti Field near village Jhetaniyon-Ki-Dhani - Barmer tehsil) and the most recent one the hydrocarbon discovery in the Bhagyam discovery (near village Bothia – Barmer tehsil). The appraisals of the Mangala & the Aishwariya field have been substantially completed while the appraisals of the Shakti & Bhagyam fields are in progress.

2.3 Estimated Oil Reserves in the Area

The initial estimate of oil reserve of the Mangala discovery is in the range of 450-1100 million barrels and Aishwariya is in the range of 130-470 million barrels. The recoverable reserves are estimated to be 120 - 335 million barrels for the Mangala field and 20 – 80 million barrels for the Aishwariya field. These figures have been independently assessed by the international experts DeGolyer and MacNaughton.

The southern fields are much smaller in terms of the estimated reserves. The oil reserves estimated for Saraswati & Rageshwari field are approx. 6.5 million barrels and 3.9 million barrels respectively.

Recent discoveries such as the Shakti & the Bhagyam discoveries are yet to be appraised, however based on the results of the on-going seismic and exploratory drilling program, it is reasonable to assume that the cumulative oil reserves in the RJ-ON-90/1 block as a whole is expected to be substantial and the discoveries are seen to be commercially viable for further development. The discoveries to date has the potential to augment by upto 10% India's current hydrocarbon production volume and thereby

substantially contribute to the energy demand of the country.

2.4 Overview of Proposed Hydrocarbon Development Project

This project proposal addresses the **development of five fields** viz. Mangala and Aishwariya oil fields in the Northern Zone of the block, Saraswati and Rageshwari oil fields and Rageshwari gas field in Central Zone of the block. All the above fields are located in the Barmer district, Rajasthan. The overall map of the RJ-ON-90/1 block showing the discovered fields is given in **Fig. 2.4.1**.

CEIL proposes to develop all the above fields concurrently and the projects are expected to be completed by October 2007. It is likely that some of the smaller fields may be targeted for early production and may start commercial production before the completion of the larger field development.

The development of the block can be done in many ways. The various options for development are dictated by the variation in the quality of oil & its treatment requirements, logistics & infrastructure requirements, in-field constraints etc. Briefly, the development concept will be to have single or multi well pads, from where the well fluid flow lines will be connected to a common flow line. The well fluid will be routed to one or more Group Gathering Stations (GGS) where the crude will be processed. The well fluid which is a combination of oil, formation water and natural gas will be phase separated and the crude oil will be sent to the crude storage facility. The formation water will be treated and re-injected into the oil reservoir strata to aid in maintaining the reservoir pressure to ensure enhanced oil recovery. The natural gas will be compressed and utilized for meeting the energy requirements for process heating. The processed oil is stored in tank farm and transfer of custody to the buyer is done at the outlet flange of the tank farm / metering device. The Government of India has nominated Indian Oil Corporation (IOC) as the buyer and the processed crude will be sold to the buyer at the outlet flange of the Central Tank Farm / Crude oil storage tanks as applicable. The crude oil from the Rageshwari/ Saraswati fields may also be transported to the CTF in the Mangala field through tankers so as to enable transfer of custody to IOC from one central location.

The Mangala & Aishwariya field will have a dedicated central captive power plant to cater to the power requirements for operation of the fields. The power plant would be fuelled either by crude oil / or natural gas. The natural gas for the power plant operation will be supplied through a dedicated gas pipeline from the Rageshwari gas field located in the southern portion of the block. The power plant would be rated for a 50 MW of electrical power generation per day. Power will be distributed either through a network of

transmission towers or underground cables or a combination thereof.

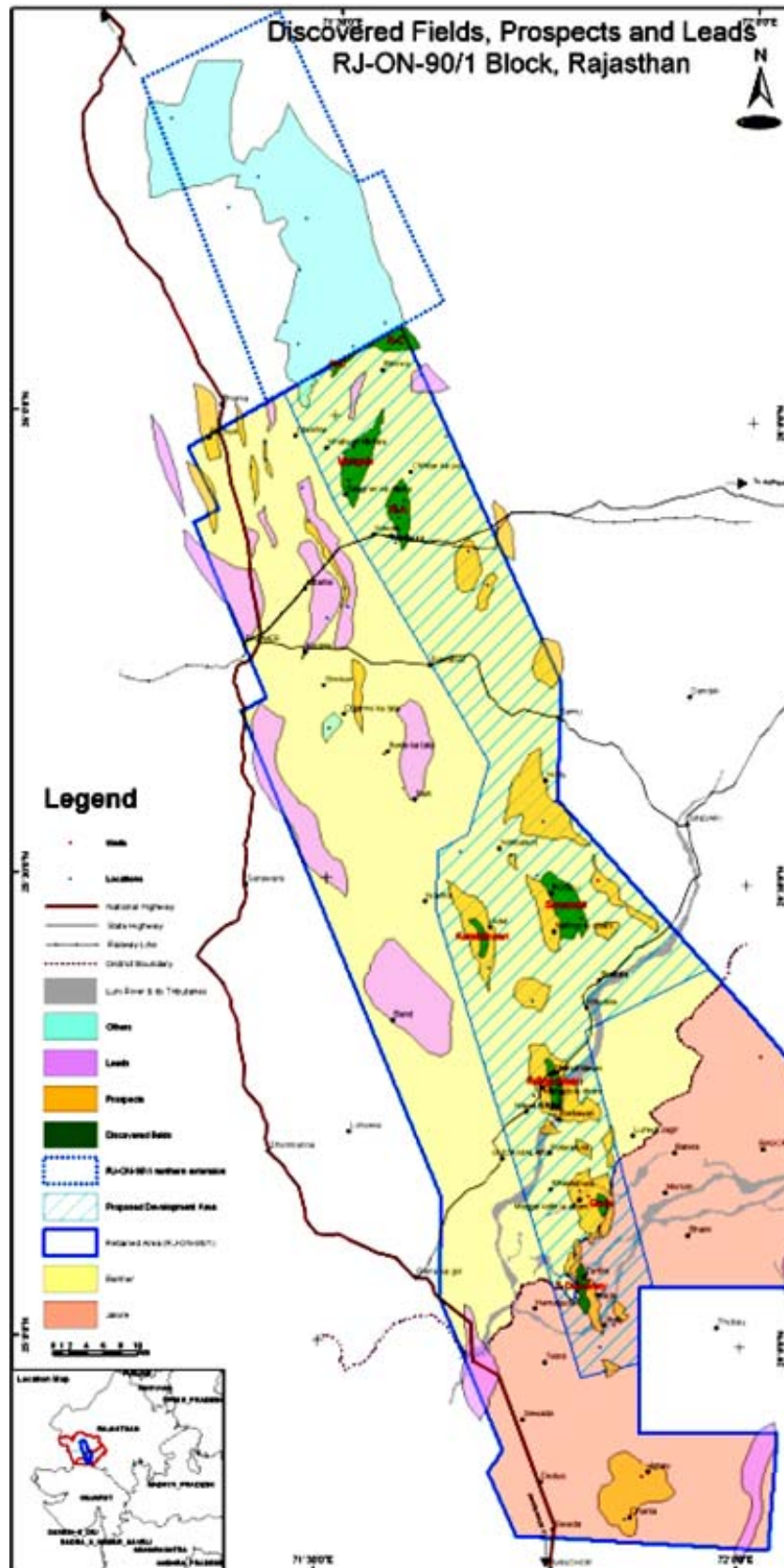


Fig. 2.4.1: RJ-ON-90/1 Block with Discovered Fields

The Mangala & Aishwariya field reservoirs would require maintenance of pressure to achieve enhanced crude recovery with saline water injection. The saline water would essentially be required to replace the volume of oil removed. A large saline water reservoir has been identified to source the supply of saline water. The saline well field will supply upto 25,000 m³ /day of saline water through a network of abstraction well and pipeline network.

Interconnecting pipelines will connect the well pads and the processing facility within the various hydrocarbon fields. There will also be interconnecting pipeline from the southern field to the northern field and a dedicated gas pipeline from the gas field in the south to the facilities in the north. Similarly there will be crude oil / natural gas pipeline feeding the captive power plant.

The field and the surface facilities will be interconnected by suitable roads and pipeline corridors for operational flexibility. The surface facilities will be installed as per applicable codes & standards, international practices and applicable local regulations.

2.5 Location Details

It is proposed to develop the following five fields in the block:

Zone	Field Name	Tehsil	District
Northern	Mangala	Baytoo & Barmer	Barmer
	Aishwariya	Baytoo	Barmer
Central	Saraswati	Gudha Malani	Barmer
	Rageshwari	Gudha Malani	Barmer
	Rageshwari Gas	Gudha Malani	Barmer

The locational details of the field and the associated facilities are described in sections 2.5.1 to 2.5.7.

2.5.1 Mangala Field

The locations of Well Pads, GGS, CPF and CTF are shown in **Figs. 2.1 & 2.2**. In the Oil & Gas Development, the exact locations can only be finalized and refined based on the on-going sub-surface investigation and the test results of the exploratory and appraisal

program. Hence their locations are tentative, till the sub-surface investigations are substantially completed. **It is therefore expected that the final Well Pad locations may be within 1 km radius of the location shown in the maps and the final locations of GGS, CPF and CTF may be within 500 m radius of the given location.** There are eight (8) alternative locations shown for 4 Nos. GGS and the final location will be any of the four out of 8 locations. Similarly two (2) alternative locations are shown in the layouts for one CPF and one CTF. The final location of CPF and CTF will be any one of the two.

2.5.2 Aishwariya Field

The location of Well Pads & GGS has shown in **Figs. 2.3 & 2.4**. The Aishwariya Field will share the common facility of CPF & CTF with the Mangala Field. As explained earlier the final Well Pad locations may be within 1 km radius of the location shown in the maps and the final locations of GGS may be within 500 m radius of the given location. The Aishwariya field will have upto 8 well pads and the GGS will be placed within the vicinity (located with-in radius of 1-3 km) of Well Pads. Group of Well Pads will be connected to the nearest GGS. Two locations out of the four GGS locations proposed will be finally selected for the development.

2.5.3 Saraswati Field

The locations of Well Pads, & GGS are shown in **Figs. 2.5 & 2.6**. The Saraswati & Rageshwari field will share a common GGS & CTF. The Saraswati field will have upto four (4) well pads and one (1) GGS. One out of the two GGS locations proposed will be finally selected for the development. **As explained earlier the final Well Pad locations may be within 1 km radius of the location shown in the maps and the final locations of GGS may be within 500 m radius of the given location.**

2.5.4 Rageshwari Field

The locations of Well Pads are shown in **Fig. 2.7**. The Saraswati & Rageshwari oil field will share a common GGS & CTF. The Rageshwari oil field will have upto six (6) well pads. **As explained earlier the final Well Pad locations may be within 1 km radius of the location shown in the maps.**

2.5.5 Rageshwari Gas Field

The Rageshwari gas field is an integral part of the Rageshwari oil field. The locations of Well Pads & GGS are shown in **Fig. 2.7**. The Rageshwari gas field will have upto two well pads. The Gas Collection & Processing Facility will be located at the Rageshwari oil well pad location WP2. **As explained earlier the final Well Pad locations**

may be within 1 km radius of the location shown in the figure.

2.5.6 Captive Power Plant

The captive power plant is located approx. 5 km west of the proposed CPF1 / CTF location proposed for the Mangala field development. This has been necessitated due to consideration of locating the power plant stacks away from the flight path of air force station operations. The proposed location is in Bandra village and is shown in **Fig. 2.8** and the tentative location coordinates are Longitude 71° 32' 06.68 and Latitude 25° 56' 02.93. **The exact location may undergo minor change due to technical and other considerations after the completion of the detailed engineering.**

2.5.7 Saline Water Well Field

The Mangala & Aishwariya hydrocarbon reservoir conditions require pressure support to achieve optimum exploitation of the reservoir. This is proposed to be achieved by saline water injection to maintain the reservoir pressure. The project proposes to set up a saline water abstraction well field near the village Madpura Barwala about 20 km south west of the Mangala CPF. The well field will consist of a network of 24 bore-wells, at a minimum spacing of 1 km. The locations of Bore-wells and the interconnecting piping is shown in **Fig. 2.9** The locations shown are tentative and the actual bore-well location may be within 1 km radius of the given location.

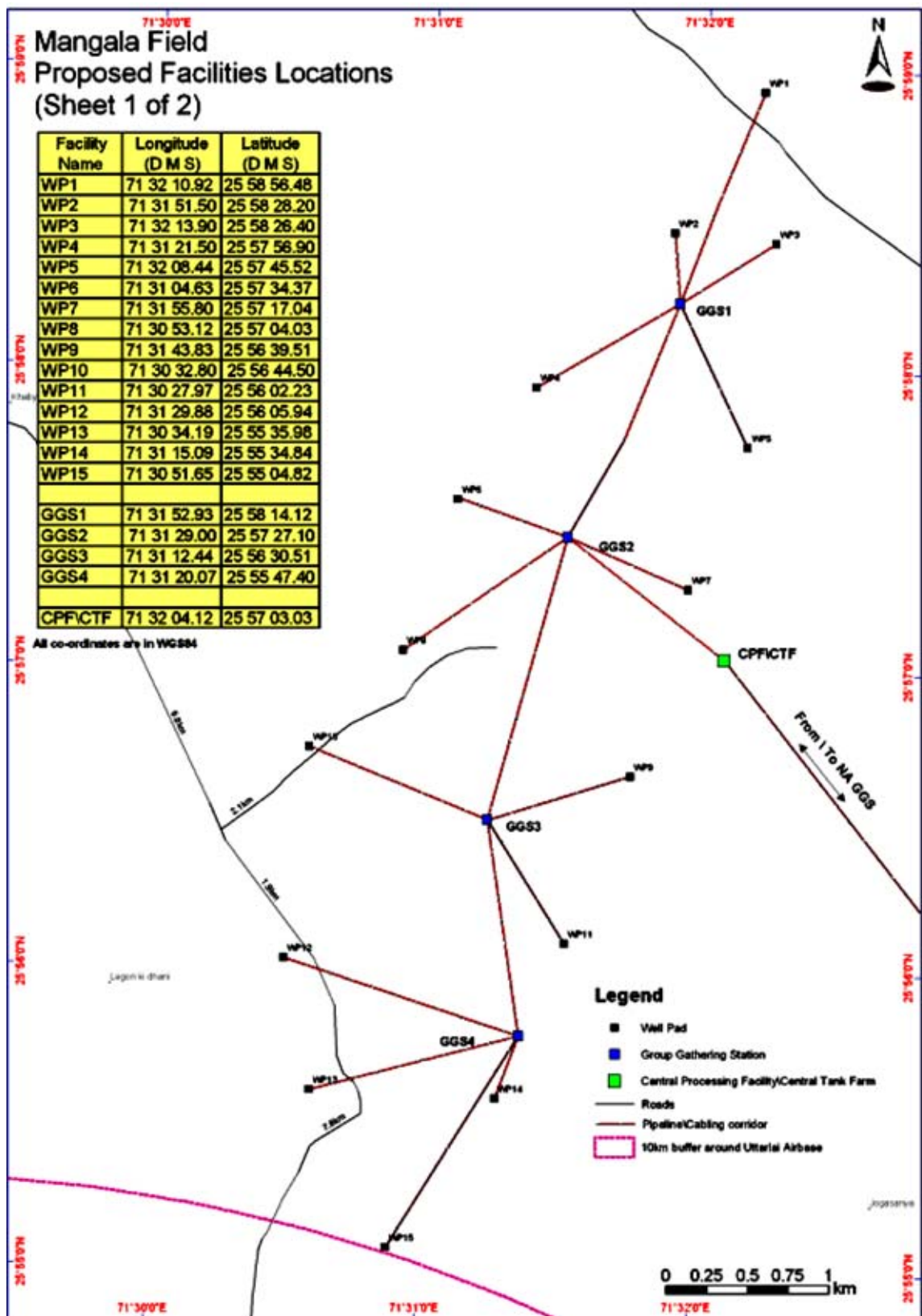


Fig. 2.1: Mangala Field - Locations of Well Pads, GGS, CPF and CTF (Sheet 1 of 2)

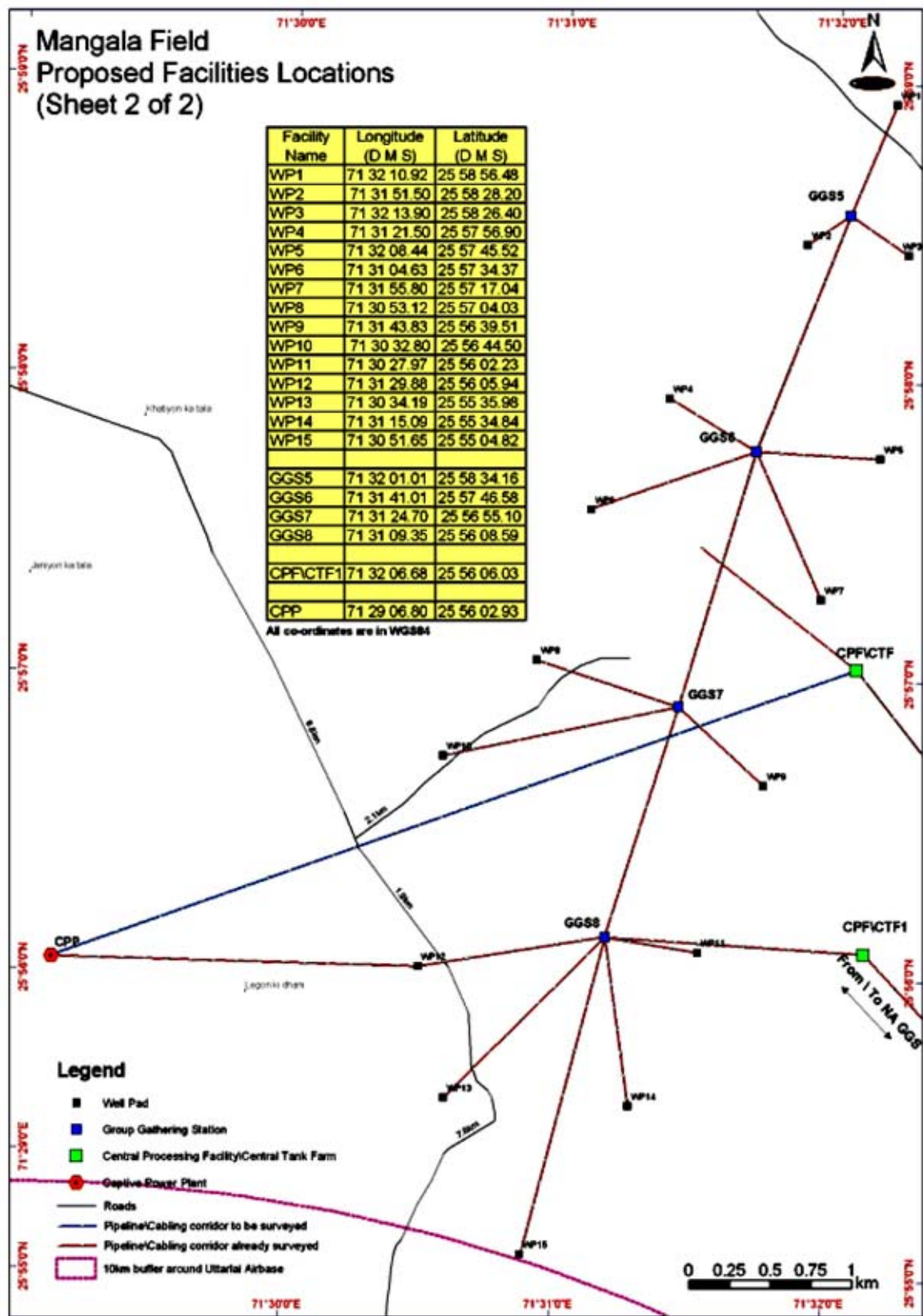


Fig. 2.2: Mangala Field - Locations of Well Pads, GGS, CPF and CTF (Sheet 2 of 2)

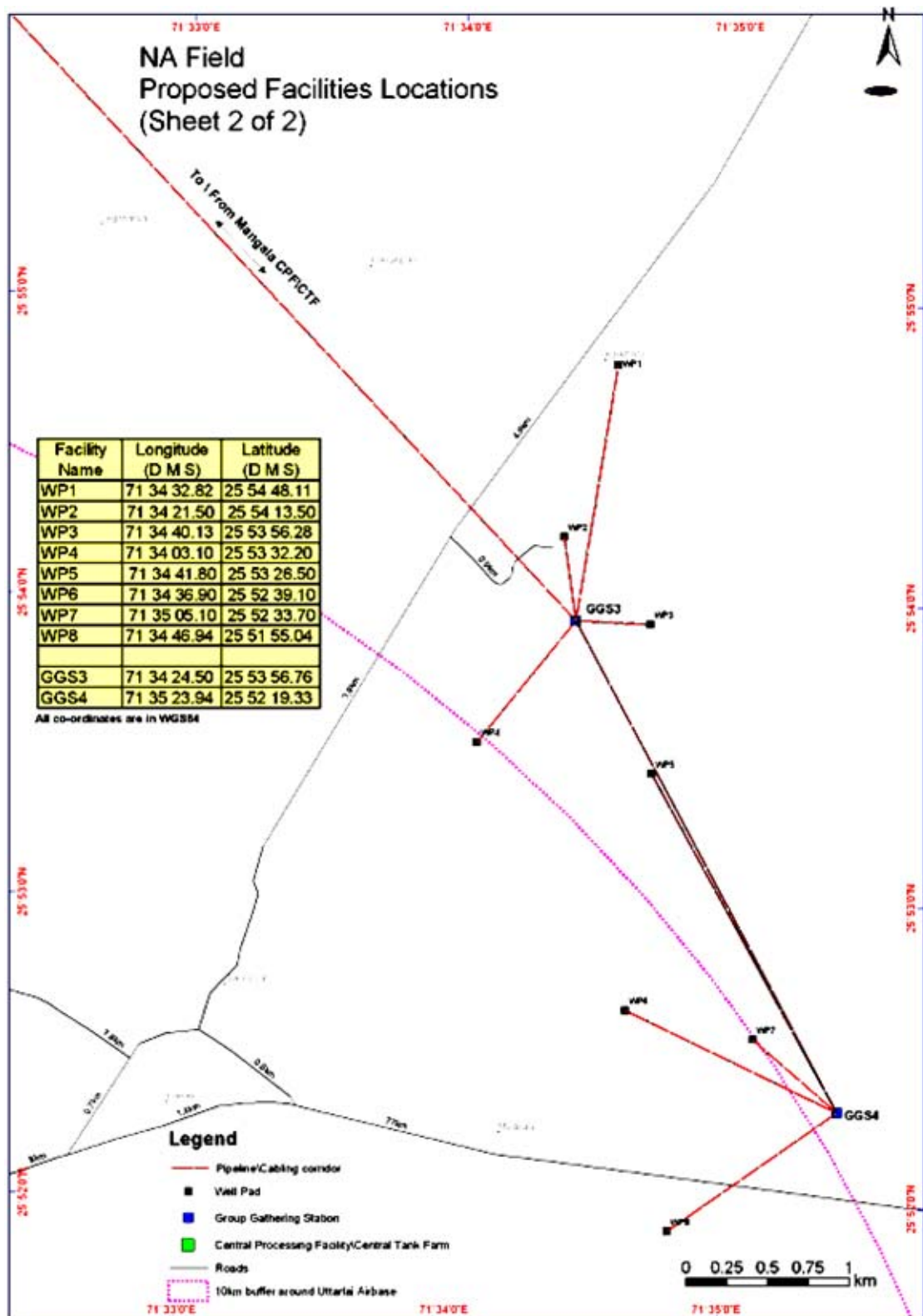


Fig. 2.3: Aishwariya Field - Locations of Well Pads, GGS, CPF and CTF
(Sheet 1 of 2)

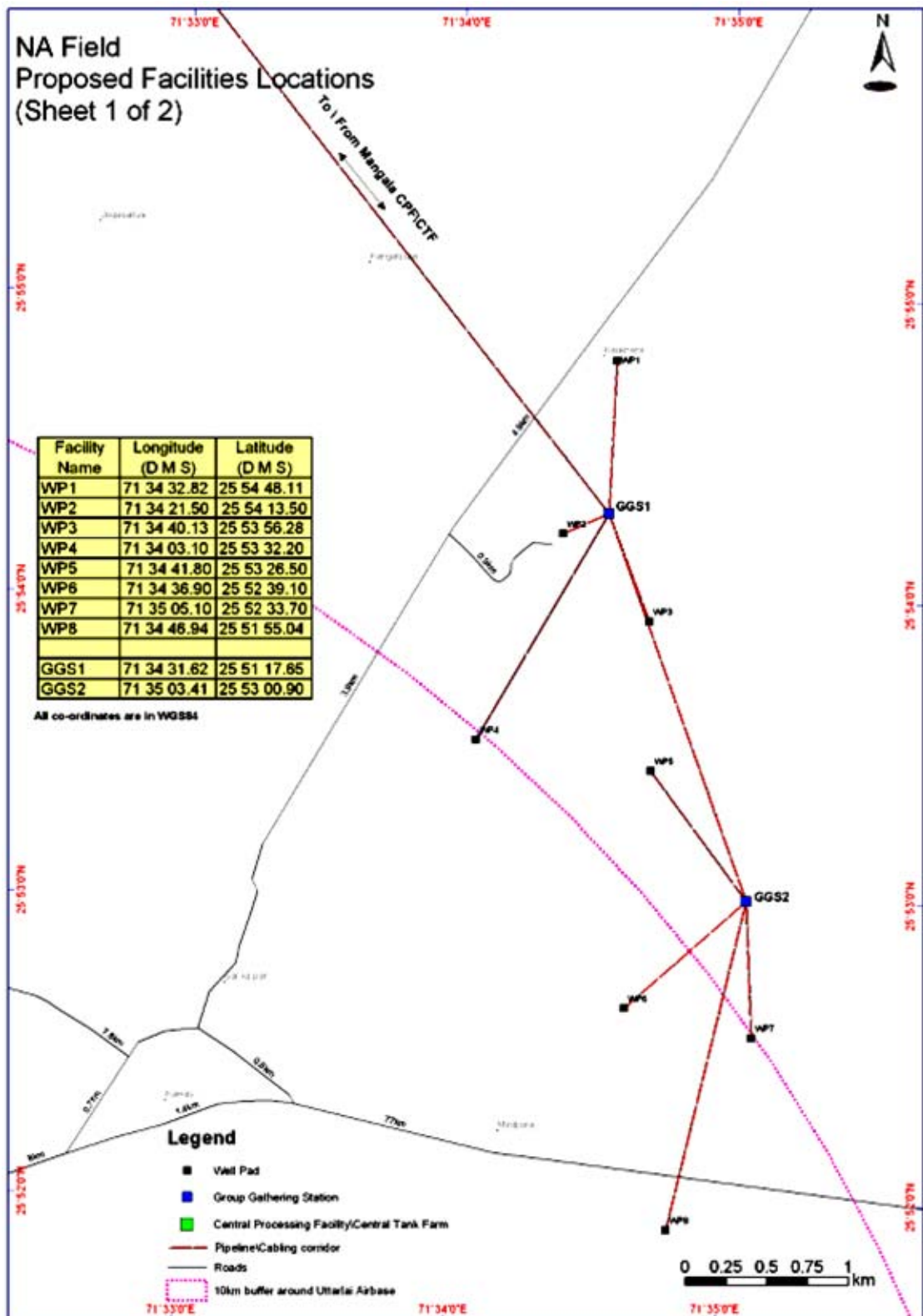


Fig. 2.4: Aishwariya Field - Locations of Well Pads, GGS, CPF and CTF
(Sheet 2 of 2)

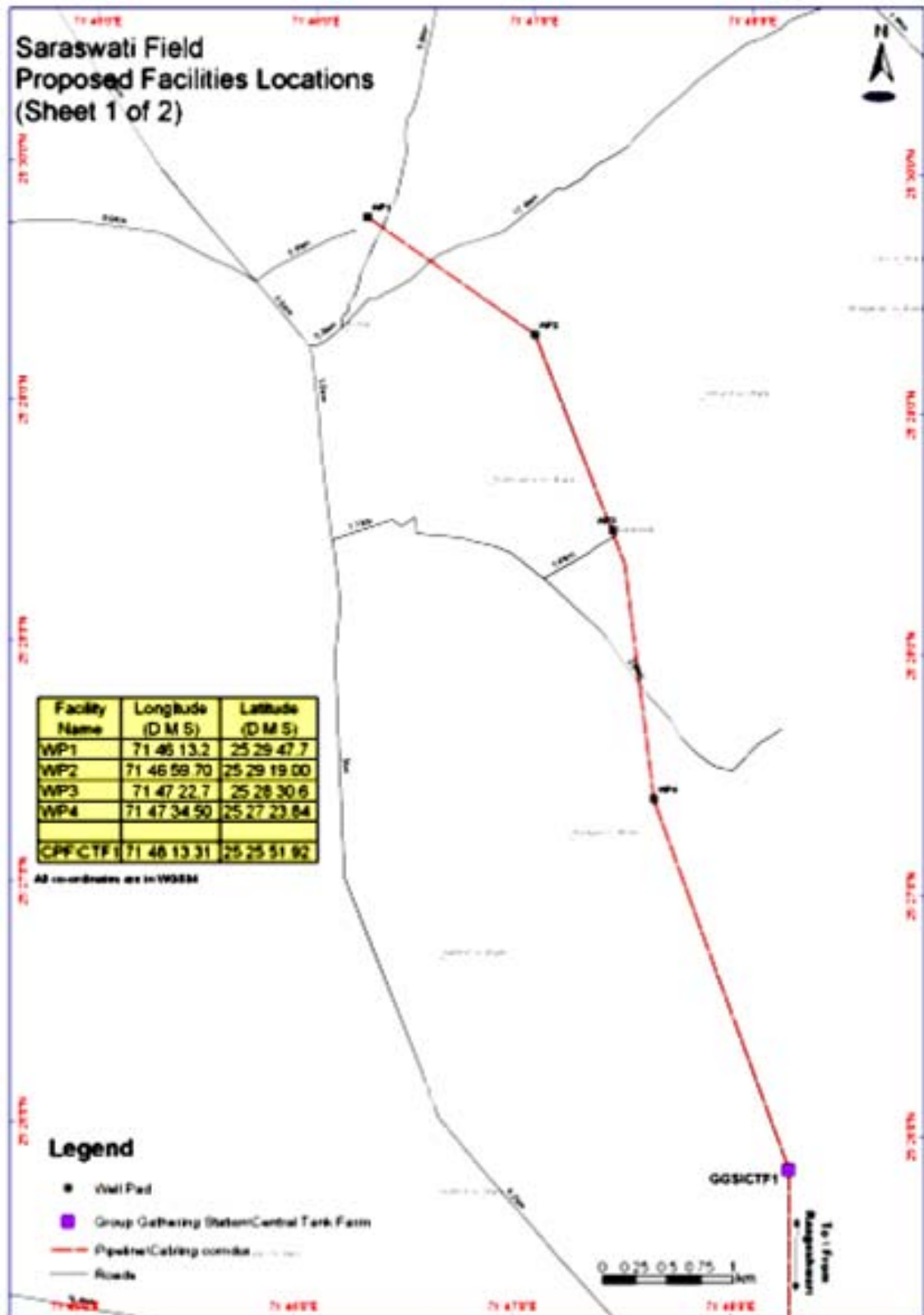


Fig. 2.5: Saraswati Field-Locations of Well Pads, GGS, CPF and CTF (Sheet 1 of 2)

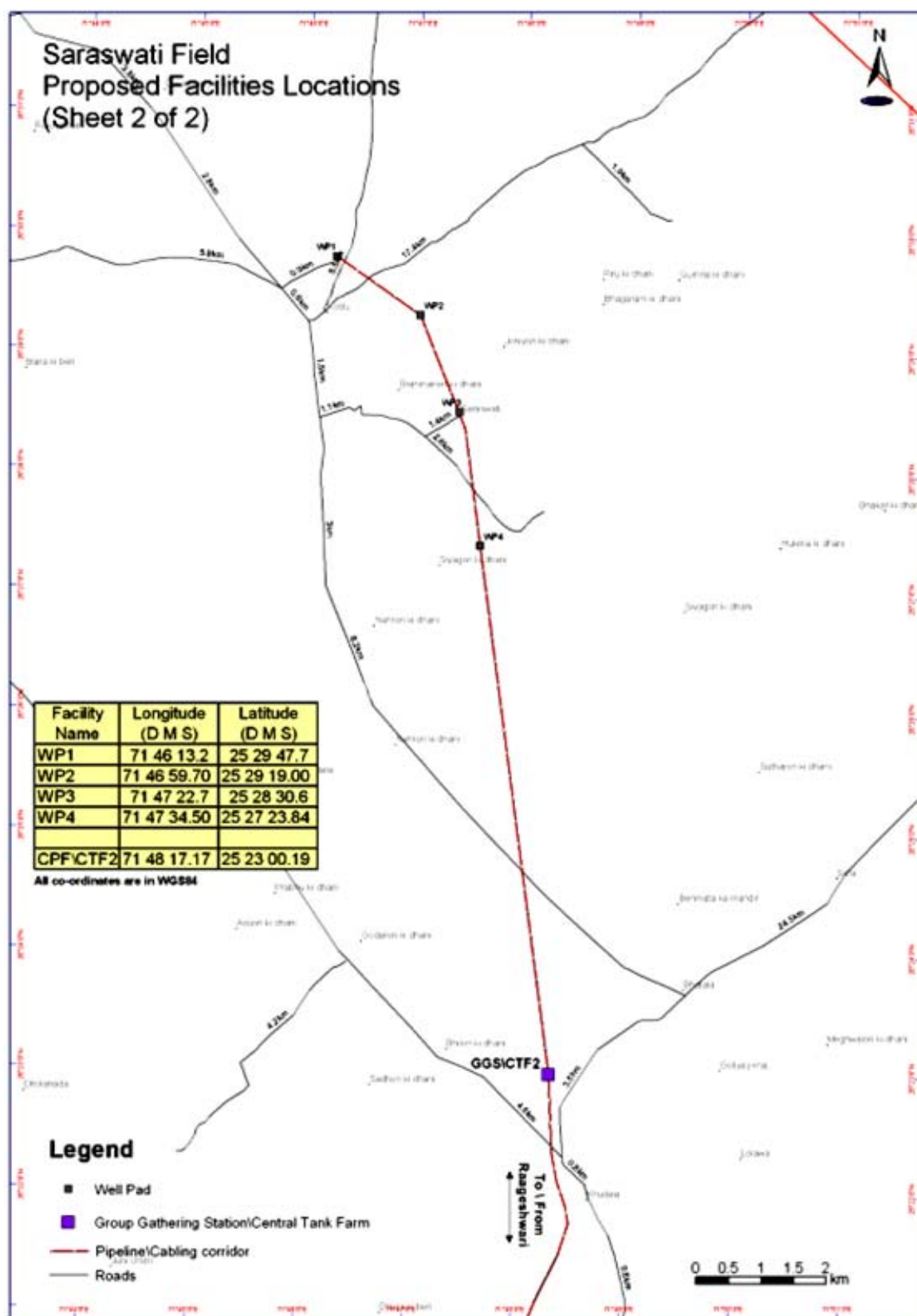


Fig. 2.6: Saraswati Field-Locations of Well Pads, GGS, CPF and CTF (Sheet 1 of 2)

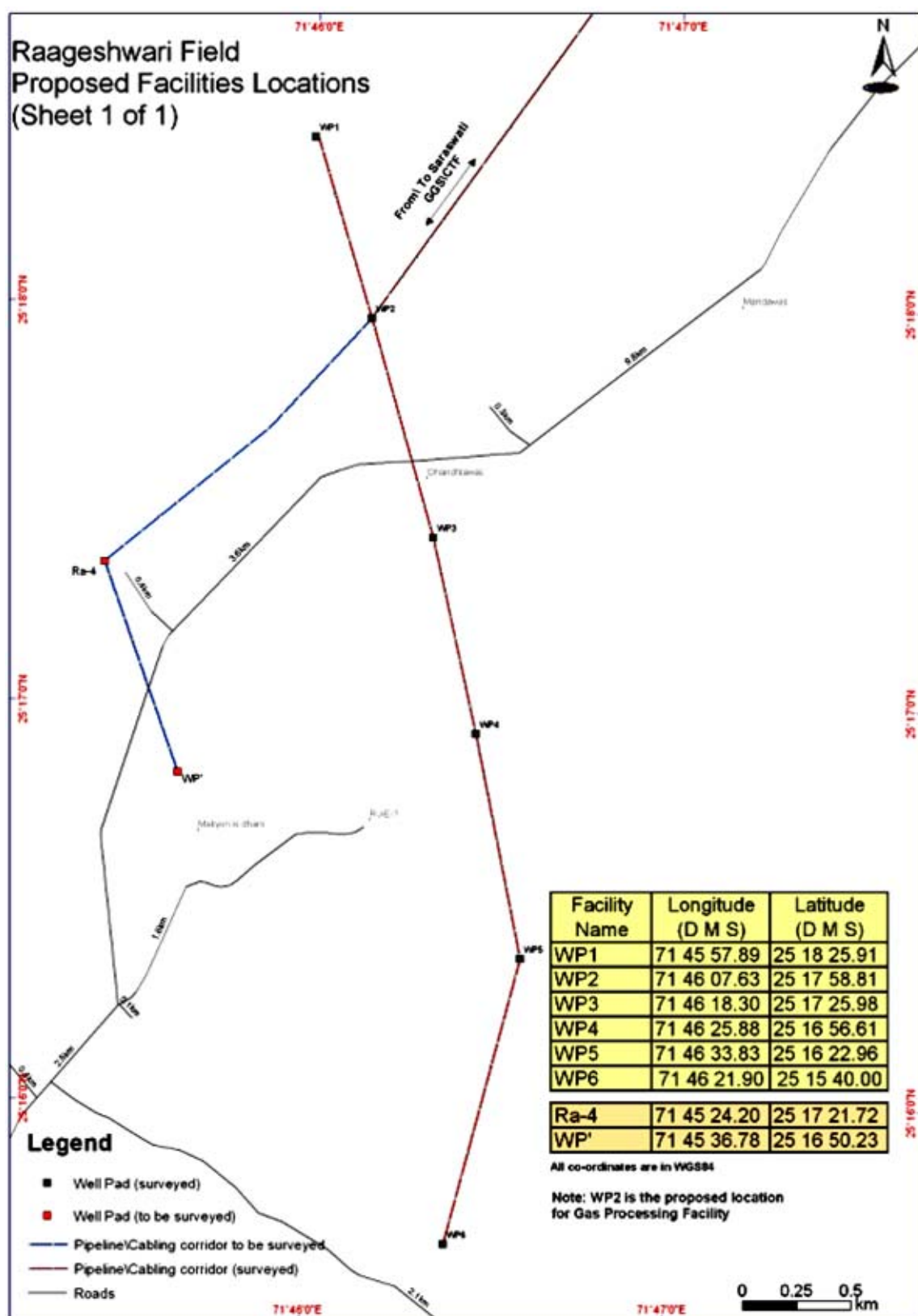


Fig. 2.7: Rageshwari Oil & Gas Field-Locations of Well Pads, GGS, CPF and CTF

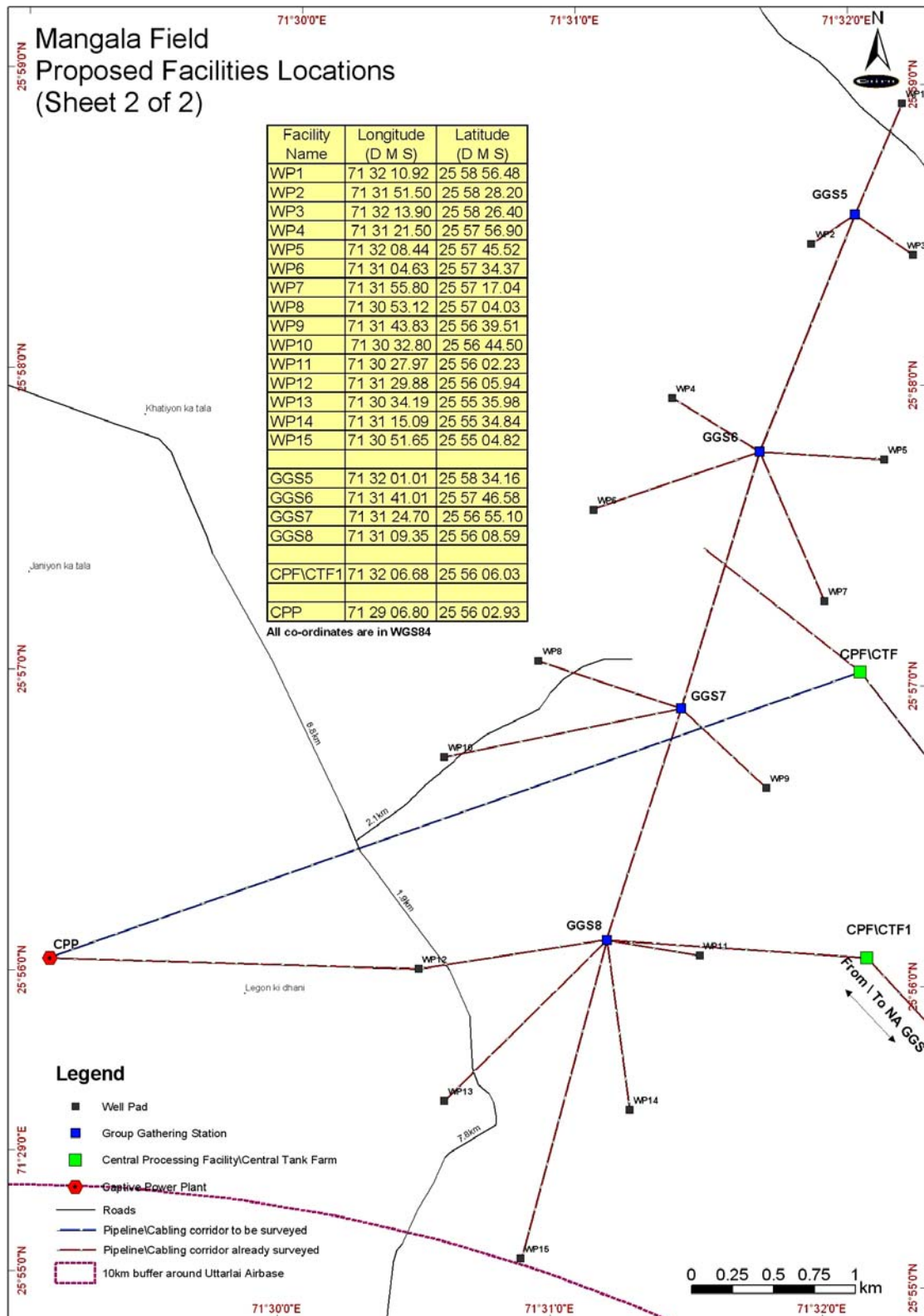


Fig. 2.8: Location of Captive Power Plant & Associated Piping Routing

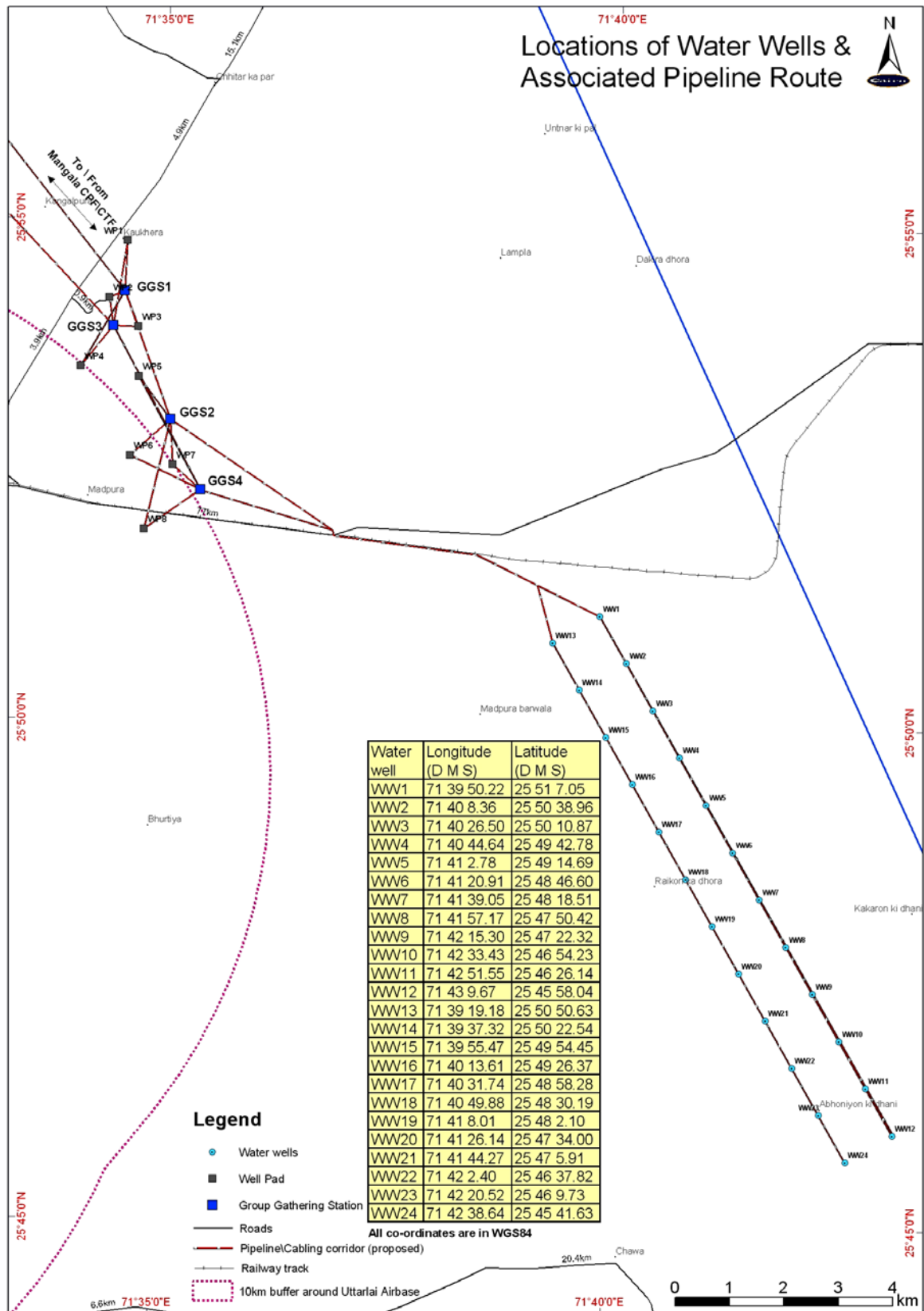


Fig. 2.9: Location of Saline Water Well Field & Piping Routing

2.5.8 Interconnecting Pipeline Corridor

There will be number of pipelines connecting Well Pads, GGS, CPF and CTF carrying well fluids, produced water, gas, stabilized oil, injection water, lift gas, hot oil supply and return etc. The pipelines will be generally laid alongside the roads connecting the facilities, as given in the layout maps. The proposed pipeline corridor routing is shown in the respective field development maps. The total length of the various pipeline corridor will be in the range between 250 – 300 km.

2.6 Hydrocarbon Production-Facilities Description & Operational Details

It is proposed to develop under this project hydrocarbon development plan four oil fields and one gas field in the block. The total crude oil production capacity from the four fields will be upto 128,000 barrels of oil per day and 30 million standard cubic feet per day of associated gas. Additionally the Rageshwari gas field will be developed to supply natural gas to meet the energy demands of the northern field (Mangala & Aishwariya fields) and will be designed to produce and process 20 MMSCFD.

Development scenarios of each field are unique and hence differ from one another. While the general unit processes are similar in all the scenarios, the differences or variations mainly revolve around grouping of and location of some of these facilities and the type of equipment and production capacities.

The overall hydrocarbon production facilities proposed under this project will broadly consist of the following elements / operations:

- Hydrocarbon Production & Water Injection wells
- Mangala field oil production facilities (Well pads, GGS, CPF & CTF)
- Aishwariya field oil production facilities (Well pads & GGS)
- Saraswati & Raageswari field oil production facilities (Well heads & GGS)
- Raageswari Gas field production facilities (Well pads, Gas processing and transfer)
- Facilities for processing associated gas and lift gas
- Central Captive Power Plant of 50 MW capacity in the northern block
- Saline water well field facilities to supply 25,000 m³/day of saline groundwater
- Injection (Dump) wells for rejected saline water from Reverse Osmosis

desalination Plant

- In-field hydrocarbon pipeline
- Infrastructure facilities required for the development project

The details of each of the above elements / operations are described below.

2.6.1 Drilling - Production & Injection Wells

The overall development plan envisages the drilling of a total of 538 wells comprising of 303 production wells and 235 injection wells. In addition upto 24 saline water wells and 6 deep injection wells are proposed to be drilled. The development plan conceives multi-pad drilling, which enables several wells to be drilled from a single drilling pad location.

CEIL has drilled several exploratory and appraisal wells in the various hydrocarbon field location in the RJ-ON-90/1 block as part of the exploratory and appraisal program. These exploratory and appraisal wells may also be converted into production or injection wells. The wells so converted will be in addition to the total wells stated above.

The maximum well depths (hydrocarbon target zones) in the northern zone would be around 1500-2000 m. The well depths progressively increases towards the central zone – Saraswati field wells would be around 2000 – 2500 m in depth and the Rageshwari wells would be in the range of 3000 – 4000 m total depth. Several wells will be drilled either vertical or deviated from a single well pad location. Slim hole well designs will be adopted where appropriate depending on the deviation and individual technical considerations. **Table 2.6.1.1** shows the details of the number of well pads, production and injection wells per pad and the total estimated number of wells required for the exploitation of each individual field.

Table 2.6.1.1

Details of Number of Well Pads, Production & Injection Wells

Field Description	Max. No. of well Pads	Max. No. of Production Well /Pad	Max. No. of Production well	Max No. of Injection Wells/Pad	Max. No. of Injection Wells	Max. No. of Wells
Mangala	15	13	195	13	195	390
N-A	8	5	40	5	40	80
Saraswati	4	6	24	-	-	24
Raageswari	6	6	36	-	-	36
Raageswari Gas	2	4	8	-	-	8
Saline water Abstraction well	Wells to abstract saline water from the Thumbli aquifer (300 – 500 m deep)					24
Reject Water Injection (Dump) Well	Disposal of RO reject water (> 1500 m deep)					6
Total	35		303		235	568

2.6.1.1 Drill Site Preparation

The site preparation involves land acquisition and clearance prior to civil works. The site needs to be graded and suitably elevated above the local flood level. Suitable foundations will be constructed to hold the heavy drilling rig equipment. Water, drilling mud and pits and cuttings storage pits etc will be prepared before the rig is mobilized. Septic tanks and soak pits will be provided to dispose off the domestic wastewater at the drill site. Prior to rig mobilization, the adequacy and strength of approach will be checked and wherever required they will be widened and strengthened.

2.6.1.2 Rig Mobilization

The rig mobilization and assembling stage invite deployment of several trucks, heavy lifting and earth moving equipment in addition to deployment of manpower.

Land based detachable modular rigs will be used for drilling on land. The rig can be detached into individual components and road transported to the location and assembled. The mobilization of the drill site involves transportation of drilling rig in modules and erected by means of mobile cranes. The drill site equipments are designed as modular

/ skid mounted type, which facilitates quick demobilization and remobilization. The installation of the drill site equipment / facilities involves about 80 trailer loads spread over 10 days. Once the site is prepared, drilling equipment, supplies and drilling personnel will be mobilized and the drilling rig will be erected and the statutory licenses obtained.

2.6.1.3 Drilling Operation

The drilling process involves drilling of the well hole across various ground layers to a predetermined depth. CEIL proposes to use mobile land drilling rigs to achieve the desired above objective. Drilling operations would commence after getting necessary clearances from the MoEF & RSPCB for the project and well in advance to the completion of the production facilities. The drilling operation would commence at the various individual field locations with multiple rigs operating concurrently and would also involve simultaneous data logging of the stratigraphy and carrying out well tests and test flaring. Typically the drilling of a well would take 15-30 days depending on the target depth and the type of rig deployed.

Well spudding is the start of drilling activity. Top-hole section will be drilled to a desired depth based on well design. After drilling top-hole section, it will be cased with a pipe called "Casing". "Casing" provides support to hole wall and secures hole section. Other than that it isolates problematic hole sections such as loss zones, shale sections, over pressurized formations etc. After running casing, space between hole wall and "Casing" (annulus) will be cemented. This process of drilling and casing the hole section continues until the final well depth (target) is achieved.

While drilling, if the formation pressure exceeds the hydrostatic pressure exerted by the drilling fluid, formation fluids break out into the well bore. This is called kick. Primary means of well control is to have sufficient over-balance over formation pressure. For some reason if an unexpected over-pressurized formation is encountered while drilling and if the well control situation arises, rig is equipped with equipment to control this situation. These are set of equipments is called "Blowout Preventers" Blow Out Preventer consists of, "Annular Preventer" (closes the annular space between drill string and casing) and or "Ram Preventer" (Pipe Rams or Shear Rams). The preventers are stacked in a sequence and this assembly of preventers is termed as "BOP Stack". Blowout prevention equipment will be installed, tested and operated according to the Well Control Manual for Drilling Operations. The BOP stack in use will be pressure tested initially before drilling out of the casing shoe and thereafter weekly.

2.6.1.4 Testing Operations

At the end of the drilling of the production wells will be tested for various parameters including flowing the wells for an extended period. The crude oil from the testing operations normally termed as pit oil will either be flared (over several days) or disposed to nominated buyer / recycler. CEIL will obtain necessary approval from the applicable regulatory organization in case of offsite disposal.

Crude oil test flaring facilities will be provided at the production well drilling locations for burning of hydrocarbons during testing. The test flare pit will be located within the drill site location with adequate safety distance considerations. The residual oily wastes if any after completion of testing phase will be totally removed and sent to the authorized waste disposal site or oil handling installations for resource conservation.

The setting out of the flare pit will be done in a manner to direct the flame away from any pockets of cultivation / existing green cover. In case unavoidable firewall will be erected to prevent any scorching of the vegetation.

2.6.1.5 Well Suspension

After completing the well drilling and well completion, the wells will be capped and closed with fencing around it to prevent unauthorized man entry or stray entry of cattle.

2.6.1.6 Drilling Mud

Drilling of wells require specially formulated muds which basically comprises of inert earth materials like bentonite, barite in water with several additives to give fluidity and filter cake characteristics while drilling. The drilling muds have several functions like lubrication and cooling of the drill bit, bring out the drill cuttings from the well bore, thixotropic property to hold cuttings during non-operations, formation of thin cake to prevent liquid loss along well bore etc. Several additives are mixed into the mud system to give the required properties. Water based and synthetic based mud systems will be used in this project.

The drilling mud is circulated during the drilling process and between the drilling of subsequent wells. In the case of WBM some spent drilling mud will be generated which will be stored in lined pits. In the case of SBM almost no spent mud will be generated as the entire SBM is re-circulated in the drilling of several wells.

2.6.1.7 Resources & Utilities for Drilling Operations

2.6.1.7.1 Water

The water requirement in a drilling rig is mainly meant for preparation of drilling mud apart from washings and domestic use. While the former consumes the majority of water requirement, the water requirement for domestic and wash use is very less. Based on land rig drilling experience, the daily water consumption will be in the range of 40 to 50 m³/day. The water will be procured through water tankers from registered water suppliers. Saline water wherever appropriate will be used since it is also suitable for drilling mud preparation.

2.6.1.8 Power

The drilling process requires movement of drill bit through the draw works which require power. Power requirement for drilling operations would be through modular/mobile DG sets. The combined power requirement during active drilling would be approximately 3000 - 3500 KVA with a diesel consumption of 6-7 KL/day. The individual DG sets will have a capacity of approximately 500 - 1000 KVA. Typically there will be 3-4 DG in operation and 1-2 DG sets as standby per drilling rig. The lean power requirement is about 500 KVA for meeting utility requirements on the rig. The exhaust stacks of the DG sets of land based rigs vent the emissions at an approximate height of 5-6 m from the ground level. The DG sets are enclosed in acoustic control enclosures.

2.6.1.9 Drilling Site Facilities

2.6.1.9.1 Camp Site

In remote operating areas where there is no acceptable local accommodation, it is necessary to provide camp facilities to house operations staff, crew and other contractor personnel. Mobile campsite will be set up on temporary leased land. Typically for each drilling campaign (consisting of drilling of several wells) a temporary campsite will be set up. The approximate area requirement will be about 1 Ha (10,000 m².)

The campsite will provide accommodation to all operational crew and the contractor personnel. At any point of time, it is anticipated that about 90 personnel will be housed in the campsite during the production well drilling campaign. The site will be self-contained with the captive power supply and water treatment and sewage treatment system. Toilet facilities are in build as part of the accommodation unit. The sewage lines from the units are connected through a pipeline system to a septic tank and soak pit system. Food and other organic waste will

2.6.1.9.2 Drill Site

Drill site construction would typically involve the construction of impermeable layer lined pits for the temporary storage of drilling fluid, drill cuttings, water storage, foundations for the drilling rig and accessories, inter-connecting drains, paved secure storage provision for chemical, HSD, lubricating oil and waste oil, drill site office and communication facilities and a sewage treatment system (septic tank and soak away pits and piping) for disposal of the domestic waste. A ground level flare arrangement comprising of a recessed concrete flare pit would be constructed to flare any hydrocarbons during well testing. The approximate area required would be approximately 20,000 m².

2.6.2 Mangala Field Development

The proposed Mangala oil development facility in the block would be adequately sized and infrastructure provided to produce upto 100,000 barrels of oil per day (~ 13,500 T of crude oil). As described earlier the development plan consists of developing well-head facilities to extract the well fluid from the sub-surface reservoir, and processing the well fluid to separate the crude oil, produce water and associated gas phases at the GGS. The crude oil will be routed through pipeline to the crude storage tanks at the CTF.

The produced water would be sent through pipeline to the Central Processing Facility (CPF) for commingling with saline water abstracted from the saline water well field and treated at the injection water treatment plant and re-injected back into the hydrocarbon reservoir through the injection wells.

The associated gas will be treated for Carbon dioxide (CO₂) removal, gas dehydrated and compressed and piped to CPF for further utilization as fuel gas. A minimal amount of gas from the low pressure separator would need to be flared. The associated gas generation is expected to be only 17 million standard cubic feet per day due to the low GoR (Gas Oil Ratio) of the Mangala crude.

The transfer of custody of the produced crude to the Government of India nominated buyer will be done at the outlet flange of the CTF. It is also envisaged that due to the waxy, low pour point characteristic of the crude mixing suitable diluent (naphtha / diesel) with the crude before pumping may be required.

The proposed Mangala field development plan is given in **Table 2.6.2.1** below. The Mangala Field Architecture is given in **Fig 2.6.2.1**.

Table 2.6.2.1
Mangala Field Development Plan

A	WELLP AD
No. of Well Pads	15
Max. Capacity of Each Well Pad (BOPD)	25,000
Max. No. of Production Wells/Pad	13
Max. No. of Water Injection Wells /Pad	13
Injection Water / Injection Well	2,500 m ³ /well
B	GGs
No. of GGS	4
Max. Capacity of each GGS (BOPD)	25,00,0
Total Field Production (BOPD)	100,000
C	CPF
No. of CPF	1 (Common for Mangala & Aishwariya)
Max. Produced water (BWPD)	306,000
Max. External (raw water) water (BWPD)	144,000
Max. Injection water (BWPD)	380,000
Max. Associated Gas (MMSCFD)	17
Max. Lift Gas (MMSCFD)	10
D	CTF
No. of CTF	1 (Common for Mangala & Aishwariya)
Storage Capacity (BBLs)	600,000

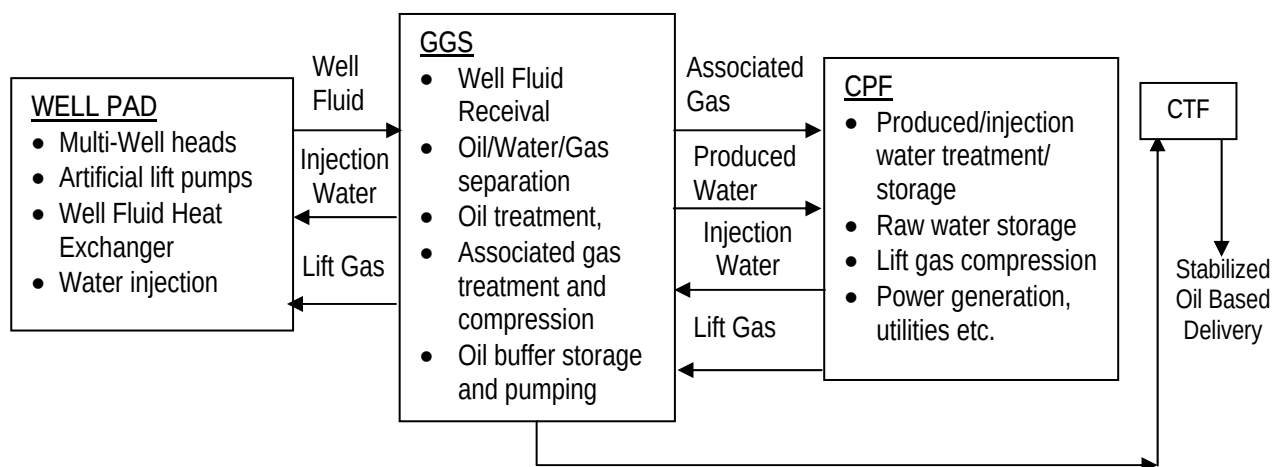


Fig. 2.6.2.1: Mangala Field Architecture

2.6.2.1 Facilities – Description

The Mangala field development facilities would broadly consist of the following facilities:

- ◆ Upto Fifteen (15) Well Pads with each well pad connected to upto thirteen (13) production wells and thirteen (13) injection wells;
- ◆ Upto Four (4) Group Gathering Stations each capable of producing upto 25,000 barrels of oil per day (~ 3,380 T per day) with following main processing units:
 - Oil/Gas/Water HP-Separator (3 phase separator)
 - Two Stage Oil Dehydrators/ Desalters
 - LP Separator
 - Oil Buffer Storage and Pumping station
 - CO₂ Removal System
 - Gas Dehydration System
 - Associated Gas Compressor Package
 - Chemical Injection Package
 - Utilities Systems
 - Electrical & Instrumentation System
 - Communication System
 - Fire Fighting Systems
 - Material & Waste Storage facilities
 - Administrative office
- ◆ One common Central Processing Facility (CPF) for Mangala & Aishwariya field development capable of treating 380,000 barrels of water for re-injection and lift gas compression of upto 10 MMSCFD. The CPF will contain the following facilities:
 - Produced water storage & treatment system
 - Raw water receipt/storage
 - Injection water treatment including desalination plant and injection

- pumping
- Potable water generation systems
- Lift Gas Compressor Package
- Utilities Systems
- Electrical & Instrumentation System
- Communication System
- Fire Fighting Systems
- Material & Waste Storage Facilities
- Secure Landfill Facilities
- Incinerator
- Helipad
- Administrative office
- ♦ One common Central Tank Farm (CTF) for Mangala & Aishwariya field development with crude oil storage capacity of 706,680 barrels of crude oil and 588,400 barrels of diluent (naphtha, diesel or equivalent) storage. The CTF may be integrated as part of the CPF and will contain the following facilities:
 - Crude oil storage tanks
 - Diluent Storage tanks
 - Crude & Diluent booster / export pumps
 - Custody transfer meter & transfer to export pipeline
 - Custody transfer meter and road tanker loading system
 - Fire Fighting System

The well pad arrangements and operations, crude processing and gas compression and conditioning and operations of utility systems are similar for Mangala, Aishwariya, Saraswati & Rageshwari oil fields, except that the equipment sizing would be varied and minor process modifications done to suit the individual field crude quality and production capacity of the Aishwariya field. The main process operations are described below. The same would be generally applicable to all the fields.

The Rajasthan Field development Project Report provides further technical details on the individual equipment sizing, operating conditions and the process flow diagram.

2.6.2.2 Well Pads & Well Head Facilities

2.6.2.2.1 Well Pads

The well pad basically comprise of Christmas tree with flow lines with suitable piping and valves. The well pads could be single well pads or multi well pads. Multi well pads would comprise of many well heads at one location and the flow lines from each well head will be brought to a common manifold before flowing to treatment facility. As the pressures from different wells could be at different levels, artificial lift pumps shall be used for pumping well fluid to surface facilities.

2.6.2.2.1.1 Artificial Lift

The wells which do not self flow would require alternative recovery methods to lift the oil. Considering the quality of oil, artificial lift is expected to be required in the Mangala development area from the beginning of field life. The artificial lift can be achieved through the use of Sucker Rod Pumps, Electrically Submersible Pumps, Progressive Cavity Pumps or Gas Lift. Some or all of these are expected to be deployed in this field development.

2.6.2.2.1.2 Well Fluid Heat Exchangers

The well fluid temperature at the down stream of choke is estimated at 47°C. The fluid would need to be heated to ensure fluid flow to the GGS. Shell and Tube type hot oil heat exchanger will be installed in the well head facility to heat the well fluid to 80°C. The hot oil system (thermic fluid) will be installed at the GGS and circulated through a closed loop system.

2.6.2.2.1.3 Chemical Injection Skid

A skid mounted chemical injection package unit will be provided for injection of pour point dispersant chemicals. This is done to prevent the well fluid to clog within the pipeline and maintain good flow characteristics. The skid mounted system will have facility for pour point chemical storage and dispensing. The system would consist of PPD tank, PPD dosing pump, demulsifier storage and dosing system, corrosion inhibitor storage and dosing system.

2.6.2.2.1.4 Well Fluid Pipelines

The well fluid will be transported to the GGS through buried pipelines carbon

steel pipeline. The pipeline diameter would vary from 3-inch to 6-inch depending on the duty conditions. Pipelines for transport of well fluid, lift gas, injection water and hot oil circulation will be laid within the pipeline corridor connecting to the GGS. The consolidated details of pipeline is given in section 2.6.8.

2.6.2.2.1.5 Group Gathering Station

The Group Gathering Stations are meant for Oil/Gas/Water separation, Oil treatment and stabilization and associated gas treatment and compression. The key sub systems in the Group Gathering Station (GGS) are listed below and briefly explained further.

- ◆ Oil/Gas/Water HP-Separator (3 phase separator)
- ◆ Two Stage Oil Dehydrators/ Desalters
- ◆ LP Separator
- ◆ Oil Buffer Storage and Pumping station
- ◆ CO₂ Removal System
- ◆ Gas Dehydration System
- ◆ Associated Gas Compressor Package
- ◆ Chemical Injection Package

2.6.2.2.1.6 Oil / Gas/Water HP Separator (3-Phase Separator)

The heated Well fluids (70°C) enter the HP-Stage separators for initial separation of Oil, Gas and Water. The separator is a spill over weir type three-phase separator and operates at 150# pressure rating. It consists of a horizontal carbon steel vessel where gravity separation of the gas, oil and water phase occurs. Provision for nitrogen blanking is provided. The separated crude is routed to the electrostatic dehydrator for further processing. The associated gas flows to the CO₂ removal system. The produce water is sent for produce water treatment.

2.6.2.2.1.7 Two Stage Oil Dehydrator / Desalter

The oil from HP separator is pumped to Two-stage dehydration/desalted. Crude oil De-hydrator/ De-Salter are used for treating crude oil emulsions. The dehydration and desalting action are performed in two stage operation. The essential parts of system are Coalescing pad and electric grids. Coalescing pads are provided to help small dispersed water-in-oil or oil-in-water droplets to combine into larger droplets which are easier to

separate by gravity. The electric grid establishes the electric field which enhances coalescing of the water droplets. The desalting action is achieved by mixing of fresh water into the feed emulsion to dilute the brine phase and thereby lower the salt content of the treated crude.

2.6.2.2.1.8 LP Separator

The LP Separator is a polishing unit to remove the residual portion of associated gas from the crude. This is done by flashing the liquid at Low pressure. The stabilized oil is stored in buffer oil storage tank and pumped through pipeline to CTF. for storage before metering and custody transfer. The gas from the LP separator is routed for flaring.

2.6.2.2.1.9 Oil Buffer Storage / Pumping System

The oil buffer storage tank is meant to provide intermediate storage of the processed crude oil before being pumped to the CTF. The crude oil storage tank consists of fixed roof type with heating coil arrangement with hot oil circulation. Crude transfer pumps are installed for evacuation of the tanks.

2.6.2.2.1.10 Carbon Dioxide (CO₂) Removal System

The associated gas in the Mangala & Aishwariya reservoir has high Carbon dioxide (CO₂) content. The CO₂ in the gas can be corrosive to the equipment in the presence of water and would therefore need to be removed. The CO₂ removal may be done by physical membrane process or DEA/MDEA (Di-Ethanol amine or Methyl Di Ethanol amine process) contacting process. The amine systems consist of air coolers which cool the gas to make it suitable for the process and then taken through contactor column, where it contacts the lean amine solution flowing down from the top the column. The process gas is in counter flow with lean amine. The CO₂ is absorbed by the lean amine. The rich amine leaving the contactor column is then regenerated in regeneration column by stripping of CO₂ and cold vented to atmosphere. The sweet gas from contactor is then routed to HP gas scrubber to knock off any liquid particles before entering the Compressor System. The gas compressors will compress the gas to suitable pressures as required for internal fuel gas service etc.

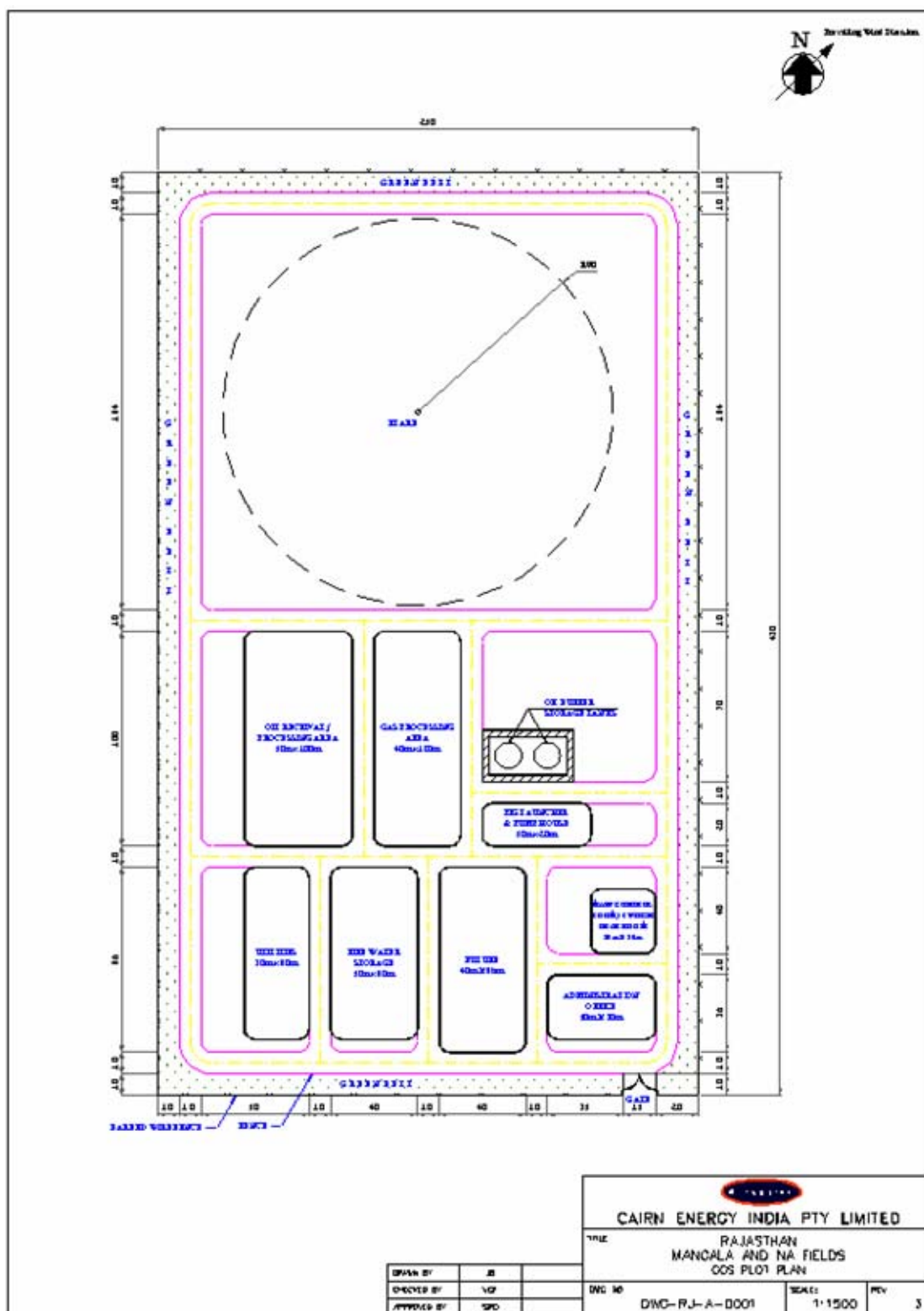


Fig. 2.6.2.1.2.1: Typical Layout-Group Gathering Station (GGS)

2.6.2.2.1.11 Gas Dehydration System

The combination of Carbon dioxide with water practically ensures that corrosive conditions will exist in plant. To avoid the corrosive environment, either CO_2 or water is required to be removed from the process gas. Water removal /gas dehydration can be done

by many process viz., Glycol dehydration and Pressure Swing Adsorption process. The dry gas from dehydration system is routed to the Compressor System. The gas compressors will compress the gas to suitable pressures as required for internal fuel gas service etc.

2.6.2.2.1.12 Associated Gas Treatment & Compression

Associated gas compressor system consists of one single-stage motor driven reciprocating compressor. Discharges from the compressor, after cooling, are routed to the knock out drum (KOD). After cooling, the discharge is routed to the fuel gas header.

2.6.2.2.1.13 Flare System

The flare system caters to the need of flaring of associated gas from shut-down / emergency and normal operations. The normal operation flaring would primarily be the separated gas from the LP separator. Flares are equipped with gas pilots and igniters with purge gas. The flare system consists of knock-out-drum (KOD), flare pump and header. Liquids from the flare knock-out-drum are routed to the oil buffer tank. The flare stack would be of 30 m height

2.6.2.2.1.14 Interconnecting Pipelines

The stabilized oil from the GGS will be pumped to the CTF through buried carbon steel pipeline laid within the pipeline corridor connecting to the CPF. Interconnecting plant pipelines for transport of crude oil, hot oil, water, associated gas, closed drain, instrument air, potable water, fire water, etc. will be laid. In-plant pipeline may consist of elevated pipeline on pipe-racks or buried underground. lift gas, injection water and hot oil circulation will be The consolidated details of the pipeline corridor is given in section 2.6.8

2.6.2.2.1.15 Chemical Injection

The chemical injection system will be similar to the details described in section 2.6.2.1.1.4.

2.6.2.2.1.16 Drainage and Sewage Disposal

The plant area will be provided with a network of surface drains to cater to the 20-year maximum intensity of rainfall expected in the area. The process drains will be closed type and will be kept segregated from the storm water flows. The rain-water flows from area that has a potential for contamination due to the facility operation will be routed to the process drain through suitable valve / isolation gate control. A check oil trap will be provided near the outlet of the storm water drain. Arrangements will be made to divert the storm water for rain water harvesting.

Sewage from the toilets of the buildings will be connected to either septic tanks / soak-away system or provided treatment in a package sewage treatment plant. The treated sewage will be used for greenbelt development.

2.6.2.2.2 Central Processing Facility (CPF) & Central Tank Farm (CTF)

The CPF / CTF will be preferably integrated into one common facility. The facility would be designed to meet the requirements of both the Mangala & Aishwariya field development.

The key sub systems comprising the CPF / CTF are listed below and briefly explained further.

- ◆ Produced water storage & treatment system
- ◆ Raw water receipt/storage
- ◆ Injection water treatment and injection pumping
- ◆ Potable water generation systems
- ◆ Lift Gas Compressor Package
- ◆ Crude Oil Storage
- ◆ Diluent Storage
- ◆ Crude Export System
- ◆ Road Loading Gantries
- ◆ Electrical Power generation & distribution
- ◆ Other utility production & distribution systems

Typical layout of CPF /CTF is shown in **Fig. 2.6.2.1.3.1.**

2.6.2.2.2.1 Produced Water Storage & Treatment System

The produced water separated in the GGS is routed to the Central Processing Facility for further treatment. The produced water is planned to be treated and made suitable for water injection. The produced water is expected to be saline and can be used for water injection. The maximum quantity of produced water estimated to be produced during the life of the field is estimated to be 306,000 barrels of water per day (~ 48,600 m³/day). The capacity of the produce water treatment plant would be approximately 336,000 barrels / day (~53,500 m³/day). The produce water treatment will consist of degassing, oil removal, sand / sediment removal through hydro-cyclone and filtration. The treated

produced water will be routed to the injection water treatment system raw water tank and co-mingled with treated additional saline water required for re-injection to maintain the reservoir pressure. The treated produced water will be stored in a closed fixed roof tank with provision for inert gas blanking (nitrogen blanking). The treated produce water will be pumped to the injection water treatment system.

In the case of Saraswati & Rageshwari field the produced water will be treated in treatment plant located at the common CPF to meet deep well discharge standards and pumped into deep dump wells (at least 1000 m deep).

2.6.2.2.2.2 Raw Water Storage

Fixed roof raw water storage tanks will be provided to store the saline water received from the saline water well field. Provision for inert gas blanking (Nitrogen blanking) will be made. The saline raw water will be pumped to the injection water treatment system.

2.6.2.2.2.3 Injection Water Treatment & Injection Water Pumping

Water injection is an important requirement in the Oil & Gas Industry and is a critical requirement for the Mangala & Aishwariya field development. Water injection as a enhanced recovery method is expected from the beginning of field life to provide for reservoir pressure and mobility. The total injection water requirement would comprise of the quantity of produced water and the additional quantity made up from the saline water source. The maximum injection water requirement is estimated to be 380,000 barrels of water per day (~ 60,000 m³/day). The quantum of injection and thus injection rate per well shall be dependant on the reservoir management philosophy. The injection system would comprise of

- ◆ Injection wells (for injection into the reservoir)
- ◆ Injection water treatment
- ◆ Injection pumping system

The source of additional injection water would be from the saline water aquifer located south east of Aishwariya field at about 9 Km away near the village Madpura – Barwala. A comprehensive study has been carried out to ensure that the water sourced from this locational has minimal impact on any existing fresh water source. The saline water aquifer and the saline well-field details are detailed in section **2.6.11**.

The injection water will be treated and raw feed water will be co-mingled with the treated produce water and routed to a desalination unit (~ 60,000 m³/day capacity) to produce injection water quality of TDS about 10,000 mg/l. This is required for the polymer

flooding process for enhanced oil recovery. The desalination unit will consist of pre-treatment, reverse-osmosis and chemical conditioning. The injection water treatment plant will have a design capacity of 66,500 m³/day. The injection water will meet the RSPCB standard for deep well

2.6.2.2.2.4 Potable Water Generation

The potable and process water required for the operation of the Mangala & the Aishwariya fields will be met by desalination of the saline water obtained from the saline water well field. It is estimated that approximately 1000 - 1500 m³/day of fresh water would need to be produced to cater to the process, domestic and greenbelt requirement. The Desalination Plant, based on Reverse-Osmosis (RO) or thermal process (utilizing waste heat) would be located in the CPF. The reject water from the desalination process will be suitably treated and commingled with the injection water. The desalinated potable water would meet the World Health Organization (WHO) standards.

2.6.2.2.2.5 Lift Gas Compression

The arrangements for the Lift Gas Compression will be similar to that described in section 2.6.2.1.2.7.

2.6.2.2.2.6 Oil Storage Tanks

The capacity of crude oil storage shall be suitable to cater to store about five days of production during maintenance of facilities. The tanks will be installed within a paved and dyked area. It will comprise of fixed roof carbon steel tanks and will be designed as per applicable codes and standard and international practices. The total maximum crude oil storage capacity will be 700,000 barrels of oil per day (~ 112,000 T). Each tank will be provided with hot oil heating coil arrangements. Crude oil booster pumps will be installed to boost and maintain adequate operating pressure in the system.

The dyked tank area will be provided with water sprinkler system and other fire fighting provisions as described in section 2.6.6.

It is intended to have one or more Central Tank Farms in the total development area. The tank farms at North and Central areas may be interconnected for operational flexibility.

2.6.2.2.2.7 Diluent Storage Tanks

In order to improve the flow characteristics of the crude, it is also planned to mix the crude with suitable diluents like naphtha, diesel, or any lighter crude before dispatching through the Buyer's export pipeline. The storage capacities for the diluents will be suitable

for 1 to 2 days requirements. The diluent tanks will be installed within a paved and dyked area and will comprise of fixed roof carbon steel tanks. The total maximum diluent storage capacity will be about 588,000 barrels of oil per day (~ 79,500 T).

The diluent will be supplied by the buyer (IOC) through pipeline and received at the diluent tank farm. Diluent booster pumps (6 no. each of 480 m³/hr capacity) will be installed to boost and maintain adequate operating pressure in the system.

2.6.2.2.8 Oil Export Custody Transfer System

The Buyers pipeline may be routed through the CTF facilities or the export pumping shall extend up to the Buyer's pipeline injection point. Export pumps shall be designed suitably for loading into tankers or pipeline. Dedicated export pumps for crude oil will be provided. The diluent and the crude will be co-mingled in the export pipeline. Custody transfer metering arrangement will be provided to measure and record the crude oil exported. It is to be understood that the diluent is being used only as a means to assist the flow of the crude in the export pipeline and is not to be included in the crude oil production quantity from the Mangala & Aishwariya fields. The diluent will be mixed with the crude oil produced after the custody transfer meter.

The installation of the export pipeline to the buyer's (IOC) refining facility is the responsibility of the buyer and approvals regarding the same will be obtained by the buyer.

2.6.2.2.9 Tanker Loading System

In addition to the export pipeline arrangement it is proposed to have tanker loading gantry system of a capacity upto 5,000 barrels of oil per day (~ 675 T) to enable road transport of limited amount of crude oil. The gantry arrangement will be able to cater to 4-6 tankers at a time. The gantry will have water sprinkler system as required. The loading bay will be paved with spill collection system.

2.6.2.2.10 Flare System

The flare arrangements will be similar to that described in section **2.6.4.1.2.8**.

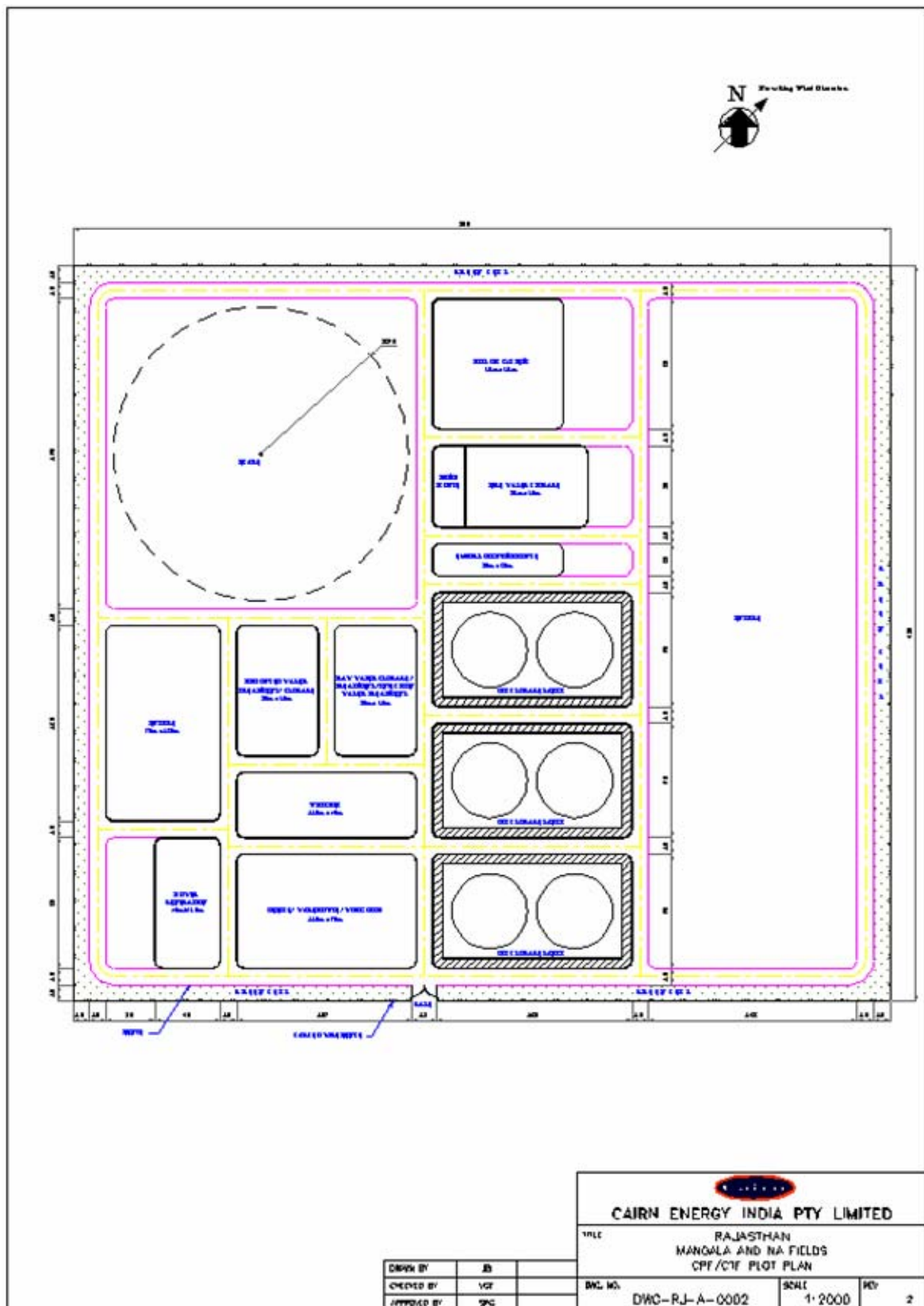


Fig. 2.6.2.1.3.1: Layout for CPF/CTF (Mangala / Aishwariya Fields)

2.6.2.2.11 Incinerator

A high temperature incinerator will be installed at the CPF for the incineration of oily wastes / oily sands / oil contaminated drill cuttings. **The incinerator will serve as a common incineration facility for all the fields described under the development plan.** The incinerator will be designed with appropriate residence time for complete combustion and will be provided with scrubber for flue gas treatment. The incinerator will be rated at a capacity of 100 kg/hr. The ash from the incinerator is expected to be suitable for use as landfill / road making. Tests will be conducted on the residue to ensure that it is within the permitted limits for use as landfill / road base, etc.

2.6.2.2.12 Waste Storage Facility

The layout of the CPF will incorporate a well-designed secure landfill site for the storage and disposal of those wastes that require secure disposal or may need to be stored in a secure place till such time as required for bio-remediation, solar drying, etc. In additions high salinity solid wastes will also need to be disposed in a secure manner to ensure no adverse impact on the groundwater / top soil.

The landfill site will be deigned to meet the storage requirements for the wastes requiring landfill disposal over the 20 year period of the field life. The landfill site will be designed and constructed based on the guidelines issued by the Ministry of Environment & Forest (MoEF) - Criteria for Hazardous Waste landfill'. The landfill site will be provided with leachate collection system and monitoring well provisions. The landfill design and other details are explained in Chapter 4 of this report.

2.6.2.2.13 Helipad

The project envisages construction of one helipad at the CPF facility at Mangala to serve the northern zone and a helipad at Saraswati field GGS to serve the central zone. The helipad would be approximately 40 m x 40 m in size with hard standing and concrete paved area. The design and installations will be as per the requirement of DGCA and in complete compliance to all safety requirements. Sufficient buffer distance would be provided from the operational areas. A paved tank area will be constructed for storage of aviation fuel. If deemed necessary pre-fabricated hanger arrangements will be made for parking. Necessary approvals from the concerned regulatory authorities will be obtained.

2.6.2.2.14 Supporting Facilities

The GGS & CPF will have an administrative and operating office block, which will house facilities like control room, stores, offices, canteen, toilet facilities, medical centre and other administrative functional areas. Communication towers and telemetric control systems

will be installed. The facility will be enclosed with safety boundary walls and security watch towers installed. The entry to the facilities will be restricted and round the clock security guards provided.

2.6.2.2.2.15 Drainage and Sewage Disposal

Arrangements as described in section **2.6.2.1.2.11** will be provided. The treated sewage will be used for greenbelt development.

2.6.3 Aishwariya Field – Facilities Description & Operational Details

The development plan for the Aishwariya field is similar to the plan and process scheme described for the Mangala Field (**Refer section 2.6.2**). As explained earlier the Aishwariya field will share common facility (CPF / CTF) set up for the Mangala & Aishwariya field for the processes to be carried out in the CPF / CTF, which mainly are produce water treatment, injection water treatment and re-injection water pumping, crude and diluent storage and waste management facilities. Thus the Aishwariya field development essentially comprises of installation and operation of well-pads, flowing the well-fluid to Group Gathering Stations to carry out phase separation, pumping the crude to the CTF, and associated gas treatment and compression and routing the produced water to the common CPF for produce water treatment. Depending on GOR of the well fluids, the gas may be flared locally (low GOR), or compressed in GGS and transported to CPF for further utilization (High GOR, Low Carbon Dioxide) or sent through CO₂ removal facility/Gas dehydration facility before being compressed and utilised as fuel.

The proposed Aishwariya field oil development facility would be adequately sized and infrastructure provided to produce upto 20,000 barrels of oil per day (~ 2,700 T of crude oil). The associated gas generation is expected to be only 3.4 million standard cubic feet per day. As stated earlier, the Group Gathering Stations (GGS) shall be placed within the vicinity (located with-in radius of 1-3 km) of Well Pads. Artificial Lift pumps are proposed to pump the oil all the way from sub-surface to GGS. Group of Well Pads will be connected to the nearest GGS. For Aishwariya development upto eight (8) Well Pads and two (2) GGS are envisaged.

The Aishwariya field development facility would broadly consist of the following facilities:

- ◆ Upto Eight (8) Well Pads with each well pad connected to upto five (5) production wells and five (5) injection wells;
- ◆ Upto Two (2) Group Gathering Stations each capable of producing upto

10,000 BOPD (~ 1,350 T per day) with following facility

- Oil/Gas/Water HP-Separator (3 phase separator)
- Two Stage Oil Dehydrators/ Desalters
- LP Separator
- Oil Buffer Storage and Pumping station
- CO₂ Removal System
- Gas Dehydration System
- Associated Gas Compressor Package
- Chemical Injection Package

The proposed Aishwariya field development plan is given in **Table 2.6.3.1** below. The Aishwariya Field Architecture is given in **Figs. 2.5.2.1 & 2**. The Process Flow Diagrams for this development are similar to Mangala field. Typical architecture of Aishwariya development is shown in **Fig. 2.6.3.1** and the typical Layout for GGS are shown in **Fig. 2.6.3.2**. The facilities proposed to be installed in the Aishwariya field GGS will be similar to that described for the Mangala field GGS. The Rajasthan Field Development Project Report provides further details on equipment sizing and related technical specifications.

Table 2.6.3.1
Aishwariya Field Development Plan

A	WELL PAD
No. of Well Pads	8
Max. Capacity of Each Well Pad (BOPD)	5,000
Max. No. of Production Wells/Pad	5
Max. No. of Water Injection Wells /Pad	5
Injection Water / Injection Well	318 m ³ /well
B	GGS
No. of GGS	2
Max. Capacity of each GGS (BOPD)	10,00,0
Total Field Production (BOPD)	20,000
C	CPF
No. of CPF	Mangala CPF will be used
Max. Produced water (BWPD)	306,000
Max. External (raw water) water (BWPD)	144,000
Max. Injection water (BWPD)	380,000
Max. Associated Gas (MMSCFD)	3.4
Max. Lift Gas (MMSCFD)	2
D	CTF
No. of CTF	Mangala CTF will be used
Storage Capacity (BBLS)	600,000

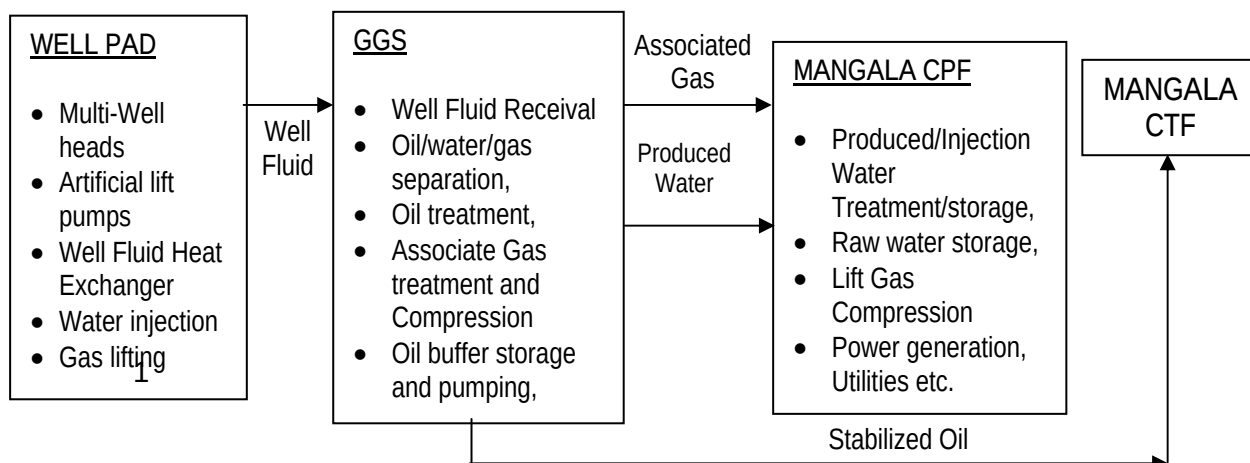


Fig. 2.6.3.1: Aishwariya Field Architecture

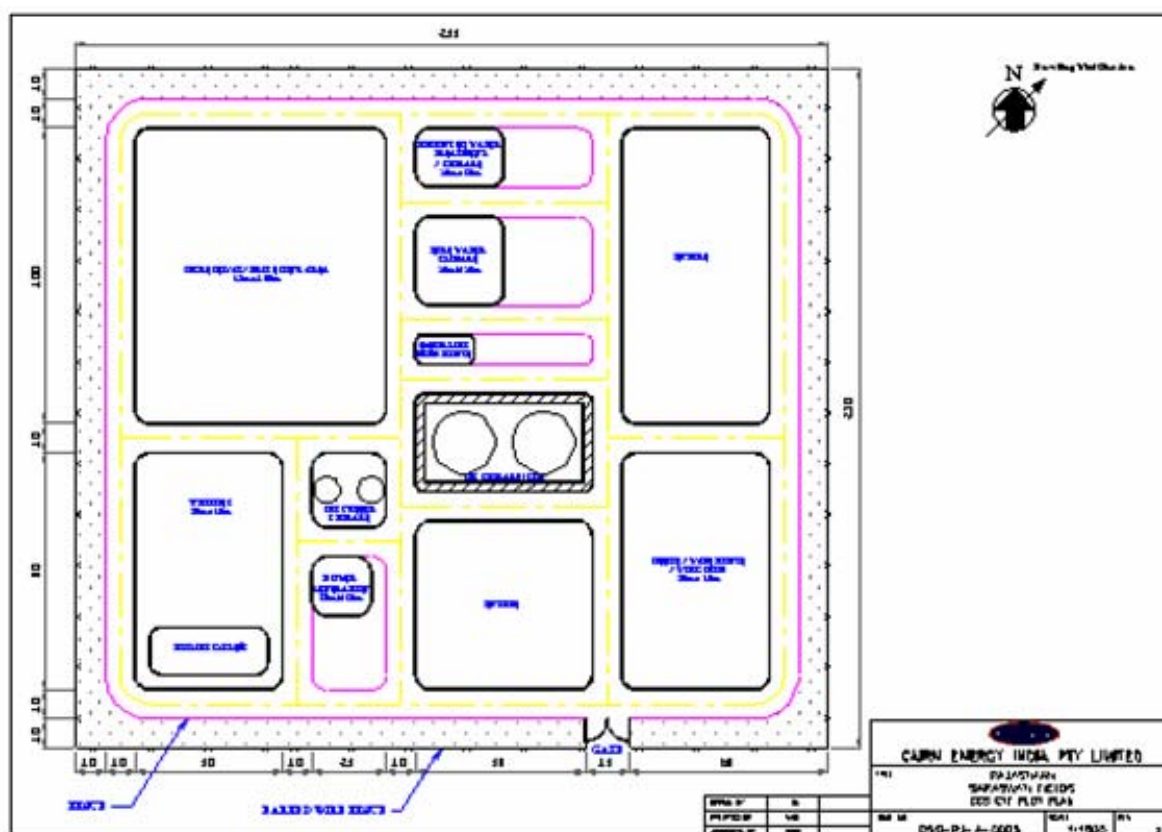


Fig. 2.6.3.2: Typical Layout for GGS

2.6.4 Saraswati and Rageshwari Fields - Facilities Description & Operational Details

The Saraswati & Rageshwari fields will have much smaller rate of oil production than the Mangala field. The development plan proposed for these fields vary in terms of the facilities and the capacity of the well pads required for their exploitation. However, the process of well fluid processing and gas compression remains the same. The development concept is to design minimum necessary facility, mainly to cater to small capacity well pads. Importantly these fields may not require artificial lift or water re-injection due to the reservoir characteristics. Under this option the oil is degassed in the well pad itself. Thus the facilities at well head will include single well/multi well pads and (oil and water)/gas separation shall be done. The oil along with produced water will be piped/trucked to GGS wherein the water is removed and the oil is processed for meeting the specification. Produced water is treated and disposed of in a dump well. Both Saraswati and Rageshwari fields will have a common GGS. Saraswati and Rageshwari field development architecture is shown in Fig. 2.6.4.1.

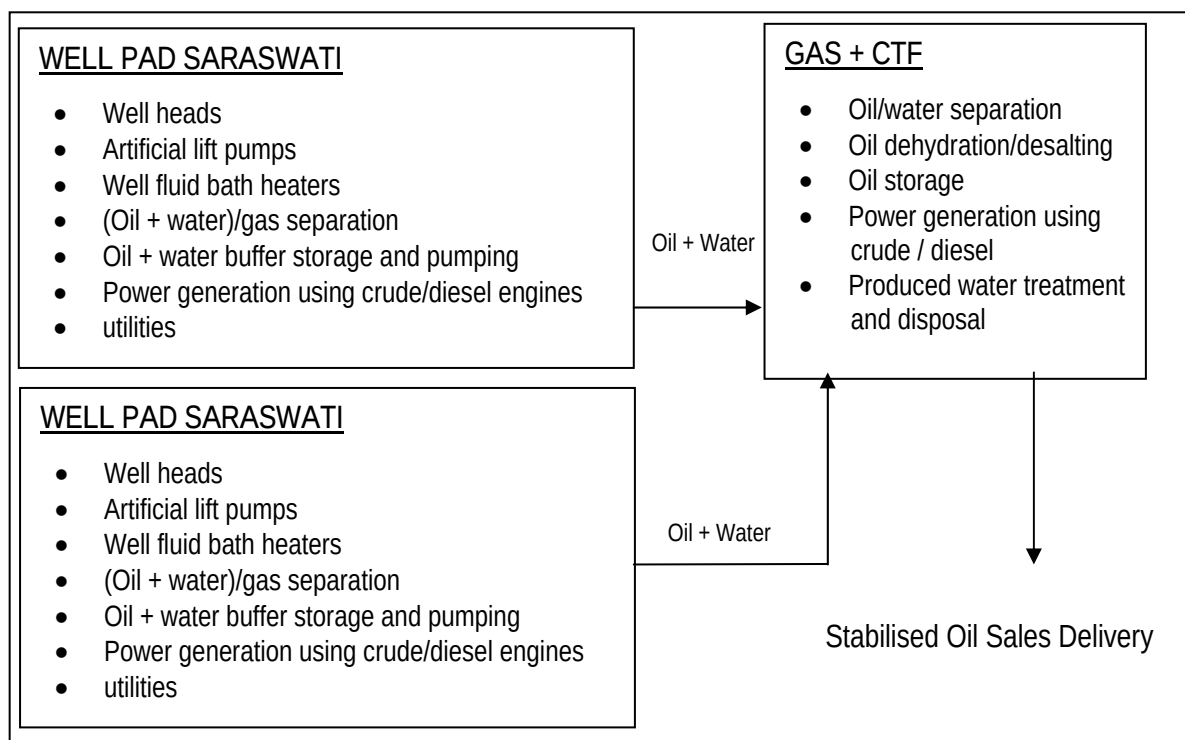


Fig. 2.6.4.1: Saraswati & Rageshwari Field Architecture

One common Central Tank Farm (CTF) will be provided which will be located adjacent to the GGS. The stabilized crude from the GGS will be piped to the CTF. Oil will be exported from CTF. Oil will be exported from CTF for high GOR fields, the associated gases will be used for power generation / flared.

The proposed Saraswati & Rageshwari field development plan is given in **Table 2.6.4.1** below.

The envisaged combined crude oil production capacity from Saraswati & Rageshwari field would be upto maximum 8,000 BOPD and maximum associated gas production of 0.35 MMSCFD.

Table 2.6.4.1

Saraswati & Rageshwari Field Development Plan

	SARASWATI	RAGESHWARI
A	WELLPAD	
No. of Well Pads	4	6
Max. Capacity of Each Well Pad (BOPD)	2,000	700
Max. No. of Production Wells/Pad	6	6
Max. Produced water (BWPD)	400	140
Max. Associated Gas (MMSCFD)	0.07	0.28
B	GGS (Common for Saraswati & Rageshwari)	
No. of GGS	1	
Max. Capacity of GGS (BOPD)	8,000	
Max. Capacity of Produced Water Treatment (BWPD)	1,600	
C	CTF (Common for Saraswati & Rageshwari)	
No. of CTF	1	
Storage Capacity (BBLs)	40,000	

2.6.4.1 Facilities – Description

The Saraswati & Rageshwari field development facility would broadly consist of the following facilities:

- ◆ Upto Four (4) Well Pads with each well pad connected to upto six (6) production wells for the Saraswati field;
- ◆ Upto Six (6) Well Pads with each well pad connected to upto six (6) production wells for the Rageshwari field;
- ◆ Each Well Pad will be capable of producing upto 2000 BOPD (Saraswati) & 700 BOPD (Rageshwari) and will have the following facilities
 - Artificial Lift
 - Oil + Water / Gas Separator
 - Fuel Gas Filter System
 - Oil + Water Storage Tank
 - Truck Loading System
 - Crude / DG / Gas based Power Generator Set
 - Flare System

- Fire Fighting System
 - Utilities Systems
 - Electrical & Instrumentation System
 - Communication System
 - Material & Waste Storage facilities
- ♦ One common Group Gathering Stations capable of producing upto 8,000 barrels of oil per day (~ 1,100 T per day) & Central tank Farm capable of storing 40,000 barrels of crude oil. The GGS / CTF will have the following facilities:
- Oil/Gas/Water HP-Separator (3 phase separator)
 - Two Stage Oil Dehydrators/ Desalters
 - Crude / Hot Oil Heat Exchanger
 - Chemical Injection Skid
 - Oil Buffer Storage and Pumping station
 - Crude Oil Storage Tank
 - Crude Oil Custody Transfer System
 - Crude Oil Export System
 - Produce Water Treatment Plant
 - Flaring System
 - Fire Fighting System
 - Utilities Systems
 - Electrical & Instrumentation System
 - Communication System
 - Material & Waste Storage facilities
 - Helipad
 - Warehouse
 - Administrative office

The process and operational details are generally similar to that described earlier. The **Rajasthan Field Development Project Report** provides the technical details such as

the PFD, equipment specification and sizing and operational parameters.

2.6.4.2 Gas Field Development

2.6.4.3 Development Plan & Process Scheme

Rageshwari Gas Field Development is intended to meet the Fuel gas requirements of Rajasthan field development.

The Rageshwari Gas Field development architecture is given in **Fig. 2.6.5.1.1**.

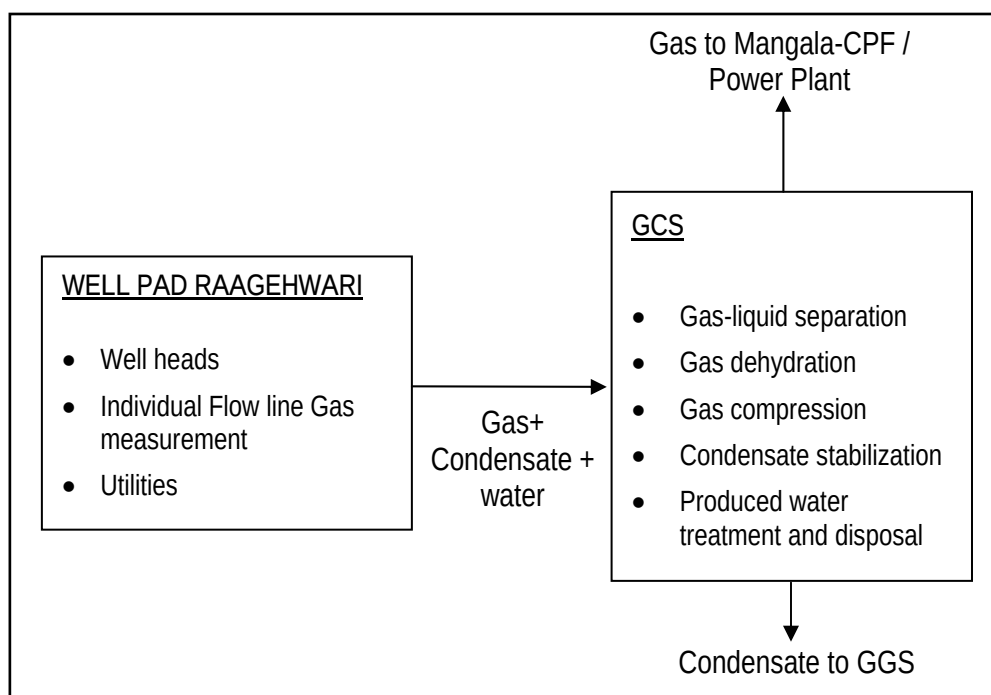


Fig. 2.6.5.1.1: Rageshwari Gas Field Development Plan

The gas is compressed, dehydrated and then sent to Mangala CPF / Power Plant to meet the fuel gas requirements for Power Generation and heating. The stabilized condensate is sent to Rageshwari Oil Field GGS for spiking into crude Oil. Facility is also provided to evacuate the condensate by road trucks.

The typical Layout for the Gas collection System (GCS) is given in **Fig. 2.6.5.1.2**. The capacities of various facilities proposed for Rageshwari Gas Field development are given in **Table 2.6.5.11**.

Table 2.6.5.1.1

Rageshwari Gas Field Development Plan

Rageshwari Gas Field	
A	WELL PAD
No. of Well Pads	2
Max. Capacity of Each Well Pad MMSCFD	10
Max. No. of Gas Wells/Pad	4
B	GCS
No. of Gas Collection Station (GCS)	1
Max. Capacity of GCS (MMSCFD)	20

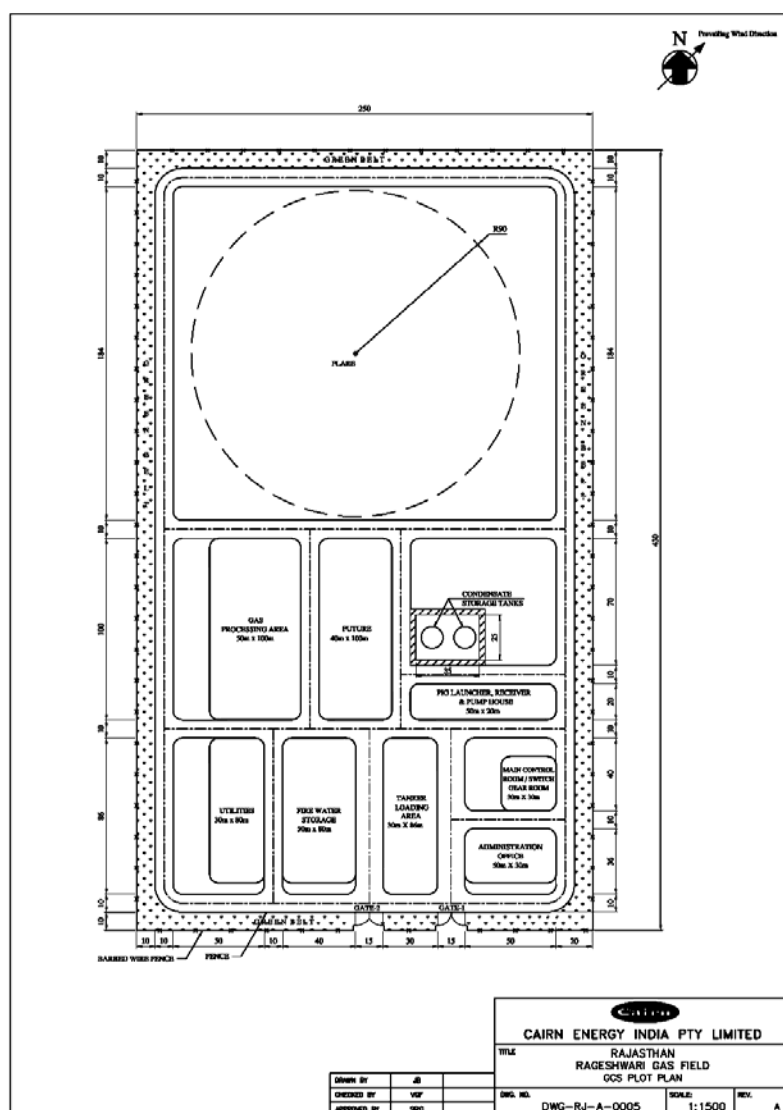


Fig. 2.6.5.1.2: Layout of Rageshwari Gas Collection Station

2.6.4.4 Facilities - Description

2.6.4.4.1 Well Pads and Well Head Facilities

The well pad basically comprise of Christmas tree with flow lines with suitable piping and valves. Multi well pads would comprise of many well heads at one location and the flow lines from each well head will be brought to a common manifold before flowing to treatment facility.

The Gas Well Head Facilities primarily consist of Well heads, gas flow meters in each flow line Production manifold, a pig launcher and utility distribution systems. Provision is kept for methanol injection during start up to tackle gas hydrate problems.

2.6.4.4.2 Gas Collection Station

The Gas Collecting Station is intended for Gas/Water/Condensate separation, Gas dehydration and Condensate stabilization.

The key sub systems in the Gas Collecting Station (GCS) are listed below and briefly explained further.

- ◆ Inlet Separator (2 phase separator)
- ◆ Suction Gas Scrubbers.
- ◆ Gas Compressors Trains (2 Working + 1 Standby)
- ◆ TEG (Tri-ethylene Glycol) contactor for Dehydrating the Gas.
- ◆ TEG (Tri-ethylene Glycol) regenerator.
- ◆ Condensate Flash Drum
- ◆ Condensate Stabilizer, Reboiler, Condensate Cooler
- ◆ Condensate Storage
- ◆ Condensate Pumping and tanker Loading System
- ◆ Local power generation using gas
- ◆ Gas metering system.
- ◆ Pig Launchers / Receivers.

2.6.4.4.3 Inlet Separator

The Well fluids enter the Inlet separators for separation of Gas and liquids comprising of condensate and water. The gas is then sent to suction gas scrubbers for

removal of entrained liquid particle before the gas enters the gas Compressors. The liquids from the Inlet Separator and suction scrubbers are sent to Condensate flash drum for separation of water and condensate.

2.6.4.4.4 Gas Compressors

The gas from Inlet Separator enters a manifold and then passes through the suction gas scrubbers before being routed to the compressors. The compressors would be reciprocating type. The gas is compressed to an estimated pressure of about 500 psig for transporting it to Central Processing Facilities in Aishwariya / Mangala field by pipeline. The gas from the Compressor is cooled by air fin coolers to near ambient temperature before entering the TEG dehydrator.

It is envisaged to install three trains of Suction Scrubber, Compressor and after cooler configuration. Each compressor will have recycle valves and capacity control. Normally two trains will be working with one train as stand by. The compressed and cooled gas from each compressor is routed to a manifold before entering the TEG contactor.

2.6.4.4.5 Gas Dehydration System

To avoid corrosion to long distance pipeline to CPP, water is required to be removed from the natural gas. Water removal known as gas dehydration can be done by many processes viz., Glycol dehydration and Pressure Swing Adsorption process. The gas from the compressors is passed through TEG contactor where the gas comes into contact with TEG. TEG absorbs the water at lower temperatures and lets out at higher temperatures. The dry gas from the contactor tower is then passed through the metering skid and then to the pipeline which delivers the gas to CPP. The wet TEG from the contactor is then regenerated in a regenerator skid and re-circulated.

2.6.4.4.6 Condensate System

The liquids consisting water and condensate from Inlet separator, Suction scrubber and TEG Contactor are routed to Condensate flash drum where water and condensate are separated. The water, being small in quantities, is then degassed and sent to solar pond for natural evaporation. The condensate is then stabilized by removing the light hydrocarbons by heating to required temperature in the reboiler and circulating through the stabilizer. The stabilized condensate is then cooled and sent to storage tanks. The condensate from the tanks can be sent to nearby Rageshwari Oil GGS for spiking in the crude or can be dispatched by road tankers for operational requirements.

2.6.5 Fire Protection System

The typical fire fighting system for the various facilities described under this project is outlined in this section. The exact details of the fire fighting systems and capabilities to be installed and developed will be finalized after the completion of detailed engineering in consultation with the concerned process and equipment vendors. It is also to be understood that not all facilities described below will be applicable for every installation. The outline of the fire system proposed is described below.

Fire protection system shall be designed in accordance with the requirements of OISD, Tariff Advisory Committee (TAC) of India, NFPA standards, design requirements and safe engineering practices and will have full capability for early detection and suppression of fire. The system will primarily consist of:

- ◆ Hydrant system.
- ◆ Foam protection system
- ◆ Deluge sprinkler system.
- ◆ Portable fire extinguisher.
- ◆ Fire detection and alarm system.

2.6.5.1 Hydrant System

The system will essentially consists of firewater storage, pumping, system pressurization and all inter connected pipe work and auxiliary fire fighting appliances. The water storage & pumping capacity and other features of this system will be finalized considering TAC recommendations.

Adequate number of engine driven/ electric motor driven fire water pumps will be provided. The pumps will be started automatically in the event of drop in header pressure. The actuation will be through pressure switches, the setting of which will be staggered to achieve sequential starting of the pumps to meet the system demand. When power supply is available, the electric motor driven pump will start first and in case of further pressure drop the engine driven pump will start. However when electric power is not available, the engine driven pump will cut-in depending on the system demand. The pumping capacity would meet the simultaneous water demand for foam protection of one oil tank, and supplementary foam hose stream in the oil dyke area, which is the maximum water demand in a single occurrence of fire. The pumping capacity should also meet the guidelines of TAC for this size of plant, considering ordinary hazard occupancy.

The fire water system will be kept pressurized by the hydro-pneumatic tank, which will take care of small leakages from the fire water system. A jockey pump, sized as per the TAC guidelines will, automatically replenish the water level in the hydro-pneumatic tank at periodic intervals. Air required for pressurizing the hydro-pneumatic tank will be supplied by an electric motor driven compressor.

The outdoor hydrant system will be provided all over the plant for exterior protection. The hydrant mains will be laid underground. Hose houses, complete with all accessories, will be provided at suitable intervals. The overall plant will be divided in several fire zones, where the fire fighting action can be pursued effectively. The pressurized main will also be connected to Sprinkler/ emulsifier System for protection of transformers & Fuel Oil storage tanks.

2.6.5.2 Foam Protection System

Fuel oil storage tanks and the surrounding dyke areas will be protected with low expansion foam system, using fluoro-protein. The storage tanks will be provided with sub-surface foam injection system and the dyke area will be provided with supplementary foam hose stream for combating spill fires. The foam protection system will be designed as per the requirements of NFPA, OISD and TAC. A central foam preparation unit consisting of at least foam storage tank, proportionating devices etc. shall be provided, to supply foam solution to the foam protection system. Pressurized water for foam system will be tapped from the outdoor main hydrant.

2.6.5.3 Sprinkler System

Automatic deluge sprinkler system will be provided for the protection of power transformer. An array of spray nozzles will be provided all around the protected area. The nozzles will be connected to the automatic deluge valve. A set of heat or smoke detectors, located in the area will sense the fire. Deluge valve will automatically open once two independent detectors sense fire.

Manually initiated water spray system will be provided for exposure protection of oil storage tanks, so that when one tank is on fire, the other tank can be cooled to guard against exposure heating. Pressurized water supply to all sprinkler systems will be tapped from the outdoor hydrant main.

2.6.5.4 Portable Fire Extinguishers

Besides, fire hydrant arrangement, portable fire extinguishers of suitable categories will be placed at control rooms, electrical switchgear room & various utility

buildings for immediate use in the event of fire. Three different kinds of extinguishers i.e. foam, CO₂ and multipurpose dry chemical (MPDC) will be provided. Each type of extinguisher has its own characteristic to fight a particular class of fire. The size and type of extinguishers will be decided as per recommendations of NFPA and relevant Indian Standard and will be placed in convenient accessible locations.

2.6.6 Supporting Facilities

Infrastructure in such development is quite substantial and critical for effective operations management. Some of the key infrastructure requirements are:

- ◆ Ware House
- ◆ Support Services
- ◆ Work shops
- ◆ Laboratory
- ◆ Communication Centre
- ◆ Living Quarters
- ◆ Helipad / Air strip

The Infrastructure may be provided in a central location closer to the Northern facilities. This could be annexed to CTF or CPF as suitable. This is dependant on various factors including logistics requirements etc.

Ware House management shall be central to the development area and shall cater to all facilities in both North and Central zones. However there could be minimal store houses in each facility to cater for immediate needs. Works shops will be for maintenance of plant equipment, electrical and instrumentation. This will have necessary carnage and other tools & tackles as required. Laboratory services are essential to maintain the quality of products, production operations related to chemical injection etc. Latest equipment and technologies shall be provided for such services.

2.6.7 Pipeline Corridor

As explained earlier there will be number of pipelines connecting Well Pads, GGS, CPF and CTF carrying well fluids, produced water, gas, stabilized oil, injection water, lift gas, hot oil supply and return etc. The pipelines will be generally laid alongside the roads connecting the facilities, as given in the layout maps. The pipeline corridor will be about 30-m wide. The pipes will be buried and corrosion protected. The required Right-of-way will be

acquired. The pipelines sizes may vary and can be finalized only after detailed design. Probable number of pipelines in each pipeline corridors is given in **Table 2.6.8.1**.

Table 2.6.8.1
Details of Pipeline Corridor

Field	P/L From	P/L To	No. of Lines	Size	Approx. Length (Km)
Mangala	Each Well Pad	GGs	8	3" to 16"	28.4
	GGs	CPF /CTF	8	3" to 24"	12.4
Aishwariya	Each Well Pad	GGs	8	3" to 10"	17.8
	GGs	CPF /CTF	8	3" to 8"	18
Saraswati	Each Well Pad	GGs/CTF	3	3" to 10"	10.6
Rageshwari	Each Well Pad	GGs/CTF	3	3" to 10"	5.4
	GGs4 (Aishwariya)	GCS (Rageshwari)	2	6" to 12"	76.9
CPP	Mangala	CPP	4	6" to 12"	5.3
Water Wells	Bore-wells	Reservoir	8	8" to 12"	36
	Reservoir	Mangala-CPF	1	24" to 28"	20

The pipeline route survey was carried out by SECONS SYSTEMS PVT LTD. The reconnaissance survey reports for the oil field development facilities are attached as separate reports. It is to be noted that the routing and pipeline corridor length shown are tentative and may be subject to change due to site constraints. **The exact pipeline corridor alignment will be finalized after completion of the detailed engineering and detailed routing survey.**

2.6.8 Infrastructure Requirements

2.6.8.1 Land

The approximate area required for the various facilities proposed for the oil field development is shown in **Table 2.6.9.1.1**. The layout of the facilities is shown under the respective sections. It is to be noted that the land areas shown are tentative and may require to be modified. The exact areas required will be finalized after the detail engineering and finalization of the layout of the facilities.

Table 2.6.9.1.1

Estimated Land Requirement

Field	Facility	No. of Facilities	Area / Facility (Ha.)	Total Approx. Area
Mangala	Well-Pad	15	2.5	37.5
	GGS	4	15	60
	CPF & CTF	1	50	50
	Power Plant	1	30	30
N-A	Well-Pad	8	2.5	20
	GGS	2	12	24
Saline Water	Water-Well	24	0.50	12
	Reservoir	1	1	1
Reject Stream Injection	Dump Well Field	6	0.50	3
Saraswati	Well-Pad	4	2.5	10
	CPF&CTF	1	7.5	7.5
Raageswari	Well-Pad	6	2.5	15
Raageswari Gas	Well-Pad	2	2.5	5
	GCS	1	13.5	13.5

The total land requirement for the proposed development plan would be approximately 290 Ha. The land will be acquired from private / government lands after obtaining due statutory approvals. Crop and land compensation will be paid as determined by the revenue officials.

2.6.8.2 Power

A key feature of the Rajasthan oil development project is that it is expected to have a high electrical demand because of the requirements for artificial lift wells (ESPs, PCPs), water injection, transfer of high viscosity fluids and the large distance between facilities. The power requirement for the Northern zone fields will be met by captive generation at a centralized power plant using either crude oil or natural gas or a combination as fuel. **(Refer Section 2.6.10 – Captive Power Plant details).**

The energy demands of the central zone fields will be met by captive generation at individual facility location by generating sets fuelled by HSD / Crude oil / Natural Gas.

In general all facilities will have the necessary electrical energy receiving,

distribution, earthing and control systems. The systems will be designed and operated to international safety norms for oil field installations. The initial estimates of power requirements for the project are given in **Table 2.6.9.2.1** below. It is to be understood that these figures are subject to change based on the detailed engineering and actual equipment selection and facility layout.

Table 2.6.9.2.1
Estimated Power Requirement

Field	Facility	Total Operating	Source
Mangala	Well-Pad	4,700	Common Captive Power Plant
	GGS	8,000	Common Captive Power Plant
	CPF/CTF	27,000	Common Captive Power Plant
	Desalination	3,000	Common Captive Power Plant
N-A	Well-Pad	1,280	Common Captive Power Plant
	GGS	2,100	Common Captive Power Plant
Saline Water Well	Bore-wells	1,200	Common Captive Power Plant
	Reservoir	300	Common Captive Power Plant
Saraswati	Well-Pad	2,460	Onsite 500 KW Genset (Crude / HSD / Natural Gas)
	CPF	930	Onsite 1500 KW Genset (Crude / HSD / Natural Gas)
Raageswari	Well-Pad	2,280	Onsite 500 KW Genset (Crude / HSD / Natural Gas)
Raageswari Gas	Well-Pad	70	Supplied from Raageswari GCS
	GCS	3,000	Generated at location by 2 No.-2 MW Gas Fired Engine Driven Genset

2.6.8.3 Water

The major water requirement for the project is for re-injection purpose for secondary recovery from the northern zone fields (Mangala & Aishwariya). It is estimated approximately 23,000 – 25,000 KL/day would be required. It is assumed that this quantity will be required for the full life of the field, though in actual practice as the field enters the production decline phase, the re-injection water requirement would also correspondingly decrease. This major source of water will be saline water sourced from the extensive saline deep ground water aquifer in the area. The details are provided in section **2.6.11**.

The actual oil & gas processing operations do not require much water and the water requirements are limited to cooling water, wash water and potable water. The fire water requirements are only for make up for evaporation losses after initial filling is done

and hence not considered.

CEIL proposes to install a desalination plant of about 1000 - 1500 m³/day product water capacity to cater to the needs of the Mangala & Aishwariya field operation. The desalination plant would also meet the cooling water requirements of the captive power plant. Fresh water for greenbelt development and maintenance will be met from recycling the treated effluent / sewage and or fresh water from the desalination plant.

In the case of the central zone facilities, the fresh water requirements are less as compared to the northern field and will be sourced from local registered water suppliers. In case it is found feasible and suitable source of saline water exists, CEIL may install a desalination plant in the Saraswati CPF or the Rageshwari GCS and distribute the fresh water to the central zone facilities through the preliminary estimates of water requirement required for the operation of the various facilities are indicated in **Table 2.6.9.3.1**.

Table 2.6.9.3.1

Estimated Fresh Water Requirement

Field	Facility	Water Requirement (KL/day)				No. of Facility	Total Water Requirement (KL/day)
		Process Water	Domestic Water	Greenbelt Development	Total / Facility		
Mangala	Well-Pad	10	1	4	15	15	225
	GGs	100	5	45	150	4	600
	CPF/CTF	100	15	95	210	1	210
Aishwariya	Well-Pad	5	1	4	10	8	80
	GGs	50	5	20	75	2	150
Saline Water Well	Bore-wells	0.5	-	1.5	2	24	48
	Reservoir	0.5	0.5	4.5	5	1	5
Saraswati	Well-Pad	5	2	13	20	4	80
	CPF	50	10	30	90	1	90
Rageshwari	Well-Pad	5	2	13	20	6	120
Rageshwari Gas	Well-Pad	5	2	13	20	2	40
	GCS	50	10	40	100	1	100

2.6.9 Captive Power Plant

The power requirement for the Mangala and Aishwariya development is proposed to be generated in a dedicated centralized captive power plant of 50 MW capacity. The sources of fuel for this purpose are Associated Gas and or Non-Associated Gas from Rageshwari Gas Field or Crude oil. The power may be produced using either of the following units:

- ◆ Gas turbine driven Generator (Gas based)
- ◆ Gas engine driven Generator (Gas based)
- ◆ Liquid fuel fired Engine driven Generator (Crude oil or diesel based)

The crude oil will be supplied through pipelines via the nearest GGS of Mangala Field and the natural gas, will be supplied from Rageshwari field through pipelines.

The power generation will be centralized for Mangala and Aishwariya fields and distributed to different load centres / facilities. The tentative location of the Power Plant is shown in **Fig. 2.5.6.1**.

The power generation may be at 11 KV or 33 KV level, which is the optimal level for transport to long distances to reduce transmission losses. The voltage level will be stepped down to 6600/415/240V levels at the facilities as per the specific facility requirements. Suitable systems shall be provided for Emergency power, DC power systems, Sub stations for distribution, Un Interrupted Power Supply, Control power etc. The systems shall meet DGMS, Hazardous Area Classification and other standards applicable.

2.6.9.1 Technology Options

The project proposes to use any of the three options namely, Gas turbines, Crude oil fired I.C Engines and Gas fired I.C Engines for power generation. Each option is elaborated hereunder.

Option – I Gas Turbine Based CPP: Gas Turbines are widely accepted machines for power generation. These are rotating machines and work on Brayton Cycle. These machines are compact, lightweight and are supplied as completely packaged units within weather proof acoustic enclosures, ready to be installed outdoors.

The heavy-duty industrial turbines of about 10 MW capacities are around 30% efficient at ISO base load. Performance of the machine is sensitive to the ambient temperatures & site altitude; it is less efficient as compared to gas engines in smaller capacities. Their efficiency and cost both become attractive with the increase in machine capacities.

Option – II Gas Engine Based CPP: Reciprocating engines working on gas are in operation as they have higher efficiencies of about 40 to 42% with lower effect on performance due to site conditions. These gas engines are spark ignition engines, low or medium speeds having proven operating experience.

Option – III Crude Oil Engine Based CPP: Reciprocating engines working on Crude Oil are in operation as they have higher efficiencies of about 40 to 42% with lower effect on performance due to site conditions. These crude oil engines are compression ignition engines, low or medium speeds having proven operating experience.

The following options have been considered for finalization of Power Plant configuration.

- ◆ **Option – I:** Power Plant with eight (8) Nos. Fuel Gas Fired Gas turbines (7W + 1S)
- ◆ **Option – II:** Power Plant with eight (8) Nos. Fuel Gas Fired I.C Engines (7W + 1S)
- ◆ **Option – III:** Power Plant with eight (8) Nos. Crude oil fired I.C Engines (7W + 1S)

It is to be noted that the options have not been listed in order of ranking and any one or combination of the options to generate the required power of 50 MW.

The technical specifications, configuration and layout and operational details are provided in the **Power Generation Study Report prepared by Engineers India Limited** for Rajasthan Oil development project report.

2.6.9.2 Crude Oil Engine Option

The crude oil engine option consists of eight crude oil fired (7W + 1S) I.C Engine sets of Wartsila model no. 18V32 or equivalent, each having site electrical output of 7.93 MWe. The exhaust gases from the engine are utilized for Thermic fluid hot oil heating in a Heat Recovery Unit (HRU), and this hot oil is in turn utilized for maintaining crude oil temperature within pump able range.

- ◆ The heat rate for the engine at 100% load is 2066 kcal/kWh
- ◆ The efficiency of the engine at 100% load is 41.63%
- ◆ The Net power output of the plant (assuming 4% internal auxiliary power consumption) is 53.29 MW
- ◆ The total Crude oil requirement for the power plant considering seven (7) engines in operation at 100% base load will be approx. 272 MT/day

- ◆ The waste heat recovery possible from the turbine is 16.9 million kcal/h

The engine will be provided with electronic-hydraulic governor, a motor driven turning gear device, turbo-charger and engine protective devices. The lubricating system will consist of main and cylinder lube oil system crude oil storage, treatment, circulation, light fuel oil start-up system, compressed air system, cooling system, utility air and exhaust gas system. The various units will be housed in enclosed building and equipments will be provided with noise control measures so as to ensure that the noise limit of 85 db(A) at 1 m from the equipment is not exceeded.

The electrical system and instrumentation and control system that will be provided are discussed in the **Power Generation Study Report**.

Each engine will be provided with **independent steel stack of approximately 72 m height**. The height of the chimney has been estimated assuming the concentration of SO₂ in the crude oil to be 1% sulphur. The crude oil analysis from the Mangala field indicates that the sulphur content is less than 1%.

The effluent treatment system is described in section **2.6.10.5**. The fire fighting system is described in section **2.6.6**.

2.6.9.3 Gas Engine Option

Consisting of Eight fuel gas fired (7W + 1S) I.C Engine sets of model no. 20V34SG or equivalent, each having site electrical output of 7.89 MWe. The exhaust gases from the engine are utilized for Thermic fluid hot oil heating in a Heat Recovery Unit (HRU), and this hot oil is in turn utilized for maintaining crude oil temperature within pump able range.

- ◆ The heat rate for the engine at 100% load is 2095 kcal/kWh
- ◆ The efficiency of the engine at 100% load is 41.05%
- ◆ The Net power output of the plant (assuming 4% internal auxiliary power consumption) is 53.02 MW
- ◆ The total fuel gas requirement for the power plant considering seven (7) engines in operation at 100% base load will be approx. 238MT/day
- ◆ The waste heat recovery possible from the turbine is 19.3 million kcal/h

The engine will be provided with electronic-hydraulic governor, a motor driven turning gear device, turbo-charger and engine protective devices. The lubricating system will consist of main and cylinder lube oil system including lube oil cleaning system. The auxiliary systems include fuel gas system, compressed air system, cooling system, utility air and exhaust gas system. The various units will be housed in enclosed building and equipments will be provided with noise control measures so as to ensure that the noise limit of 85 db(A) at 1 m from the equipment is not exceeded.

The electrical system and instrumentation and control system that will be provided are discussed in the **Power Generation Study Report**.

Each engine will be provided with independent **steel stack of approximately 30 m height**. The analysis of the natural gas proposed to be used has no sulphur dioxide.

The effluent treatment system is described in section **2.6.10.5**. The fire fighting system is described in **section 2.6.6**.

2.6.9.4 Gas Turbine Option

The Gas Turbine option consists of seven (7) fuel gas fired (6 Working + 1 Standby) Gas turbines sets of Siemens make Cyclone model or equivalent, each having site electrical output of 9.5 MWe at generator terminals. The exhaust gases from gas turbine are utilized for Thermic fluid hot oil heating in a Heat Recovery Unit (HRU), and this hot oil is in turn utilized for heating the crude oil.

The packaged Gas Turbine Generator (GTG) will be installed outdoors in a weatherproof acoustic enclosure, which will limit the sound pressure level to 85 dB(A) at 1 meter from the enclosure. GTG enclosure will be designed as standalone equipment for outdoors installation, which is a standard feature of such turbines.

The salient operational details of the gas engine option are given below:

- ◆ The heat rate for the turbine at 100% load is 2808 kcal /kWh
- ◆ The open cycle efficiency of the turbine (Power to fuel input) at 100% load is 30.63%
- ◆ The Net power output of the plant (assuming 3% internal auxiliary power consumption) is 55.29MW
- ◆ The total fuel gas requirement for the power plant considering six (6) turbines

in operation at 100% base load will be approx. 329 MT/day

- ♦ The waste heat recovery possible from the turbine is 69.96 million kcal/h

The GTG will have a lube oil system, cooling system, speed-reducing gear box between the turbine and the generator, exhaust system will have exhaust gas ducts, expansion bellow, exhaust gas diffuser and exhaust gas silencer to limit the exhaust noise contribution to maintain an overall noise level to 80 dB(A).

Each engine will be provided with **independent steel stack of approximately 15m height**. The analysis of the natural gas proposed to be used has no sulphur dioxide.

2.6.9.5 Effluent Treatment & Disposal System

The effluents generated from the power plant operation are oil contaminated wastewater. It is estimated approx. 100 – 120 m³ /day of oily wastewater will be generated from the power plant operation.

The oily wastewater will be collected through process drains into a central holding pit for uniform volumetric loading into a oil/water separator. The floating oil will be skimmed and the dissolved oil will be removed by aid of chemical flocculation / dissolved air floatation systems. The oily sludge will be collected in a sump and periodically transferred to the CPF at Mangala field. The deoiled water will be subjected to activated sludge treatment, followed by filtration through dual media filter. The treated effluent will meet the land discharge standards stipulated by RSPCB and will be used for greenbelt development.

The domestic sewage from the plant operation will either be treated in septic tank-soak pit system or combined with the biological treatment stage of the oily water ETP.

2.6.10 Injection Water Sourcing & Saline Water Well Field

2.6.10.1 Need for Water Injection

In addition to the normal 'domestic' requirements for water for staff and site facilities, the project needs large quantities of brackish or saline water for injection into the oil reservoir formations to maximize the recovery of oil.

When oil wells are drilled into an oil reservoir, the oil will normally be pushed out by the pressure of water underlying the oil and the gas that comes out of solution as the pressure of the oil drops immediately around the well. These pressures are usually sufficient to force the oil to flow to the surface, and this method of production is called primary production.

However, in many cases the pressure declines rapidly with production, and the recovery of oil is poor – more than 90 per cent is often left in the reservoir. This will be the case in the Fatehgarh reservoir (Barmer basin), where the oil is relatively viscous, the natural water pressure is low and there is relatively little gas in the oil to expand and drive the oil out.

In cases like these, it is preferable to provide some form of pressure support to the production process. This usually consists of injecting water into the reservoir beneath the oil (**Fig. 2.6.11.1.1**). This water injection maintains the reservoir pressure, helping to force the oil out to the surface; the flow of water through the reservoir also enhances production by helping to 'sweep' the oil from the pore spaces in the reservoir rock, a process known as secondary recovery. This greatly increases the production efficiency, enabling recovery of up to three times as much oil as would be possible with primary production.

2.6.10.2 Saline Injection Water Requirement

CEIL estimates that maximum saline water demand will be about 25 ML/day (25 000 m³/day) for injection and other purposes for its Mangala & Aishwariya field operations . This is the maximum peak demand that is likely to arise during oilfield operation and includes water for site use. **Over the period during which the fields will be operating, it is expected that the average demand will be much less than 25,000 m³/day.**

It is important that the water should be free of suspended particles, which would clog up the pores in the reservoir and prevent the injected water from entering it easily. It must also be free of microbes, which can reproduce very rapidly and form colonies that can block up pore space or lead to precipitation of minerals in pipelines, reservoir pores or in the injection wells. It is also important that there is very little dissolved oxygen.

CEIL commissioned a study by Water Management Consultants Limited (WMC), the UK office of an international water consultancy group to study and recommend a suitable source of supply of upto 25 ML/day (25 000 m³/day) of saline water, sustainable for at least 25 years, **without adverse effects on local water supplies or communities.**

WMC has presented their findings and recommendation in their report **Cairn Energy – Oil Field Development – Water Resources Study - Phase-I**. The findings of the studies are that saline ground water was expected to be a suitable source, **with ample renewable saline water resources were available within the Mangala & Aishwariya**

field development area within the RJ-ON-90/1 block. The study also identified other possible sources and carried out a techno-commercial and availability risk evaluation.

2.6.10.3 Recommended Option - Saline Well Field Source in RJ-ON-90/1 Block

The identified source of saline water resources suitable for abstraction for injection water purposes is located in the extensive Tertiary sandstone formation (Thumbli Formation) in the northern portion of the block. The Thumbli Formation is a laterally extensive sandstone and claystone unit. It consists of sands and semi-consolidated sandstones, with occasional shales, underlain in part of the basin by a shale sequence called the Thumbli Shale. The Thumbli Sands are largely coincident with the GWD-designated Tertiary Sandstone ground-water zone. The seismic surveys carried out for oil exploration have allowed the lithostratigraphic units to be correlated throughout the basin and the geological structures to be mapped. The techniques used for oil exploration have been used to map the aquifer units. In this way the Thumbli Sand has been mapped from its outcrop at the northern limit of the licence block for over 100 km to the south where it is oil-bearing in the Rageshwari Oilfield. **(Refer Fig. 2.6.10.3.5.1)**

Hydraulically, the aquifer is predominantly confined or semi-confined, becoming unconfined to the north and west. **The aquifer covers an area of approximately 2800 km² and has saturated thicknesses of the order of 400 m.** **(Refer Fig. 2.6.10.3.5.2).** Data from pumping tests suggest that significant permeability (hydraulic conductivities of up to 100 m/day) is present in the north east; seismic and other data imply that permeability decreases towards the west and south. Average recharge, based on the water-table fluctuation method, is estimated to be about 30 mm/year based on data for 1994-2003.

The volume of the Thumbli aquifer (excluding the shales) is estimated from geophysical data to be $9.5 \times 10^{11} \text{ m}^3$ (WMC, 2004, Appendix B). Assuming an average porosity of 20 per cent, this would imply a pore volume of $1.9 \times 10^{11} \text{ m}^3$. With an abstraction rate of 25,000 m³/day for 25 years, the volume of water required for the oilfield would be $228 \times 10^6 \text{ m}^3$. This volume – probably far more than is likely to be needed therefore represents only 0.12 per cent of the volume of water in storage in the aquifer.

The WMC assessment at the conclusion of the Phase 1 Study (WMC, 2004) agrees with GWD and CGWB that a considerable, currently undeveloped, saline ground-water resource is present in the southern two-thirds of the Thumbli aquifer. It appears that this resource could be abstracted from a well field south and east of the existing fresh-water fields using tubewells with yields estimated at 1000-1500 m³/day at 500 to 1000-metre spacings. This conclusion is based partly on the results of an investigative ground-water

model study (WMC Report - Section 1.5).

The fresh water in the Thumbli aquifer occurs as a lens 'floating' on top of more saline water as isolated pockets. The water is abstracted from well fields at Bhadka, Bhimda, Khanji ka Tala, Nagana and Jogasariya. The fresh water pockets of the Thumbli aquifer is heavily developed for public (PHED) water supply in the north of the basin. There is no significant ground-water development in the central and southern sections. **Fig. 2.6.10.3.5.3** is a cross-section through the aquifer showing the inferred disposition of fresh and saline water.

2.6.10.4 Saline Water Well Field Design

The conceptual design for the well field is a network of 24 bore-wells, at a minimum spacing of 1 km. These would be arranged in two rows, each with 12 bore-wells. The tentative layout of the saline well field is shown in **Fig. 2.6.7.1**.

If all 24 bore-wells were connected to a single line, then there would be a risk of interference and backflow, especially if any reflux valves failed. Therefore, groups of three bore-wells would be connected together, and pump to a central reservoir. There will therefore be 8 groups of 3 bore-wells. Within each group, 200 mm diameter pipe would be required from each bore-well to the junction point, then 300 mm diameter pipe to the reservoir. It is estimated that the pumping head for each submersible pump would be 110 m, discharging at 18.94 l/s, requiring 41 kW power at 440 V. Each bore-well would be equipped with individual pump control valves, reflux valves, flow meter and sampling tap. The collection reservoir would have a storage capacity of 2-hours pumping (about 2620 m³), from where the water would be boosted to Mangala through a 700 mm diameter pipeline 12.9 km long plus a 600 mm diameter pipeline 6.5 km long. This would require a pumping head of 50 m, discharging at 363 l/s, requiring 300 kW power at 33 kV. Other provisions are 24 switch rooms at bore-well sites, and one main booster pump room at the collection tank site.

OIL

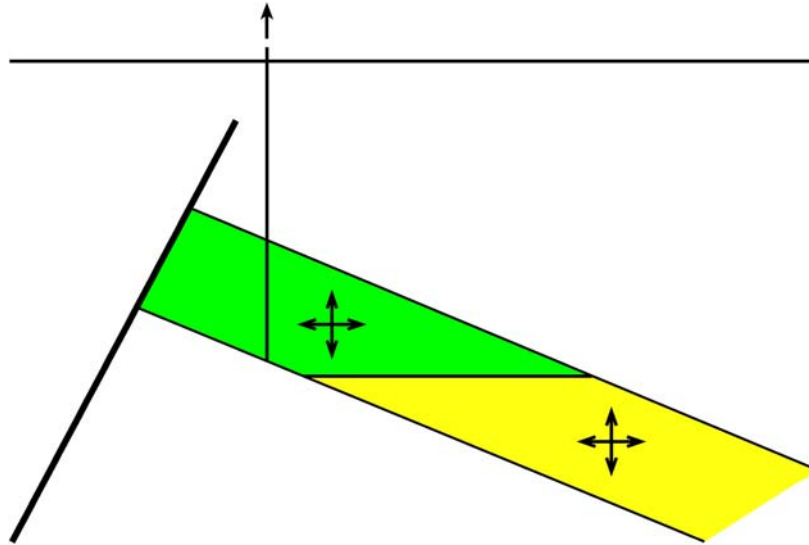


Fig. 2.6.10.1.1: Primary Production of Oil

(Production depends on expansion of the oil and the water in the reservoir, and gas coming out of solution. Recovery efficiency is low)

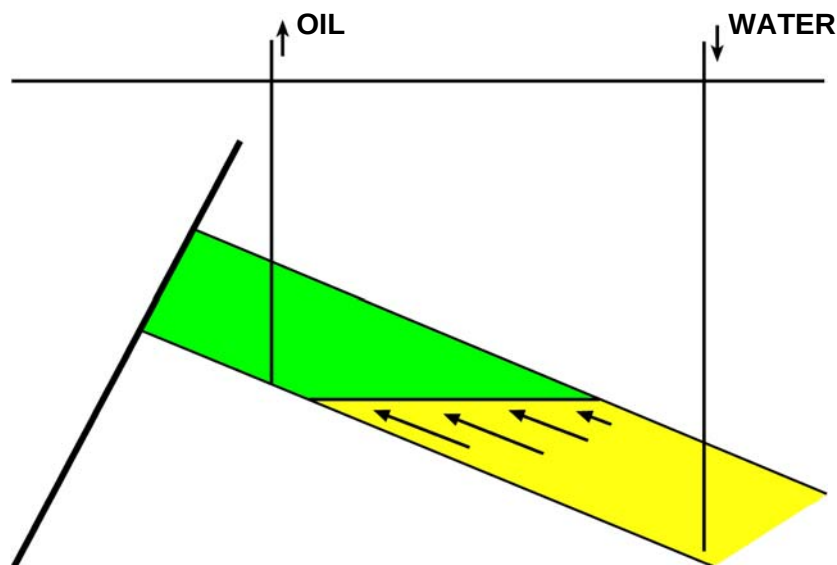


Fig. 2.6.10.1.2: Secondary Recovery of Oil Using Water for Pressure Support

(As oil is removed from the oil pool, water is injected into the water body beneath it to maintain pressure and help drive the oil from the reservoir. Recovery efficiency is greatly improved.)

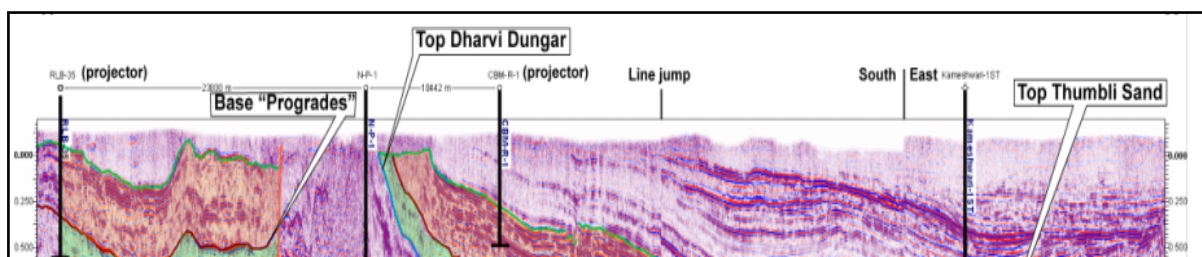


Fig. 2.6.10.3.5.01: Seismic section (approximately N-S) through the Barmer Basin showing the Thumbli Sand (red-orange) as it deepens and thins towards the south

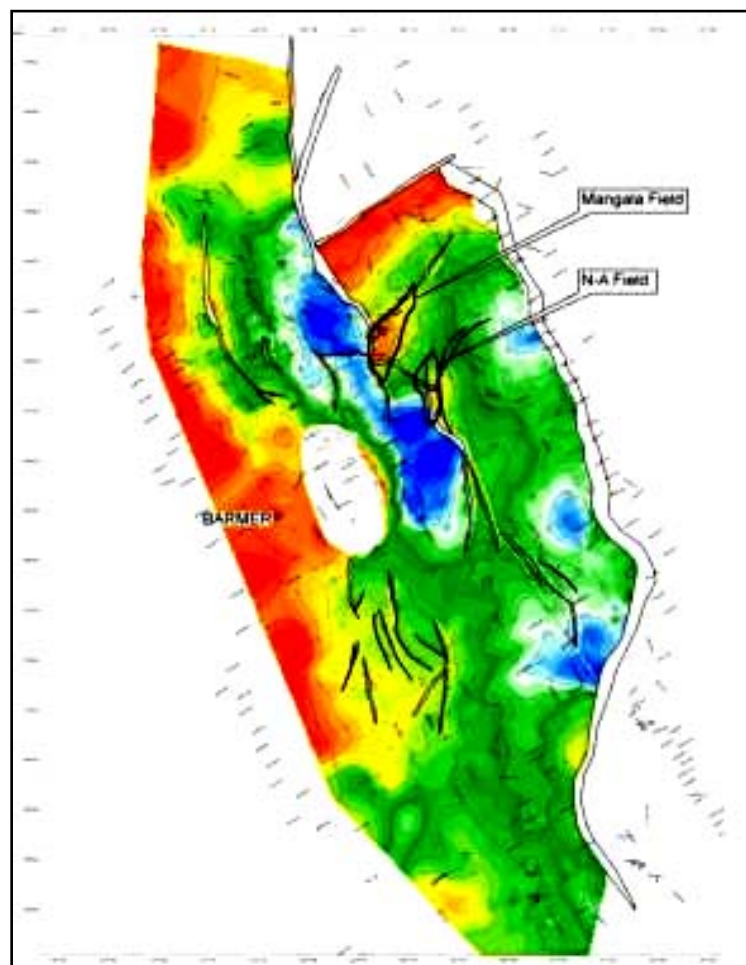


Fig. 2.6.10.3.5.2: Thickness map of Thumbli Sand Showing Areas of Maximum Thickness (>700m) in Blue

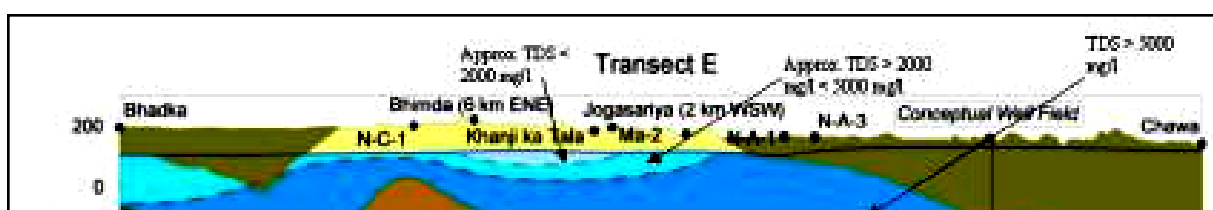


Fig. 2.6.10.3.5.3: Cross-section Through the Aquifer Showing the Inferred Disposition of Fresh and Saline Water

Chapter 3

Maximum Credible Accident (MCA) Analysis and Risk Assessment

3.1 Introduction

MCA stands for Maximum Credible Accident or in other words, an accident with maximum damage distance, which is believed to be probable. MCA analysis does not include quantification of the probability of occurrence of an accident. In practice, the selection of accident scenarios for MCA analysis is carried out on the basis of engineering judgement and past accident analysis.

Risk involves the potential occurrence of some accident consisting of an event or sequence of events. Accidental release of oil and gas to the atmosphere from well or processing equipment is studied by visualising scenarios on the basis of their properties and the impacts are computed in terms of damage distances. A disastrous situation is the outcome of fire or explosion of the released gas in addition to other natural causes, which eventually leads to loss of life, damage to property and/or ecological imbalance.

Depending on the effective hazardous attributes and their impacts, the maximum effect to the surrounding could be assessed.

3.2 Methodology of MCA Analysis

The MCA analysis involves ordering and ranking various sections in terms of potential vulnerability. The data requirements for MCA analysis are:

- ♦ Operation procedures

- ◆ Detailed design parameters
- ◆ Physical & chemical properties data
- ◆ Detailed information about facility
- ◆ Past accident data

Following steps are involved in the general MCA analysis:

- ◆ Identification of potential hazardous sections and representative failure cases for the wells and various equipments
- ◆ Visualisation of release scenarios with recourse to consequence analysis
- ◆ Damage distance computations for the released cases

3.3 Past Accident Data Analysis

Analysis of events arising out of the unsafe conditions is one of the basic requirements for ensuring safety in any facility. The data required for such an analysis has either to be generated by monitoring and/or collected from the records of the past occurrences. This data, when analysed, helps in formulation of the steps towards mitigation of hazards faced commonly. Trends in safety of various activities can be evaluated and actions can be planned accordingly, to improve the safety.

Data analysis helps in correlating the causal factors and the corrective steps to be taken for controlling the accidents. It is, therefore, of vital importance to collect the data methodically, based on potential incidents, sections involved, causes of failure and the preventive measures taken. This helps to face future eventualities with more preparedness.

3.4 Hazard Identification (HAZID)

The aim of the hazard identification review for the overall field concept is to identify events which pose a high risk to safety and the environment. As the review is at a coarse level based on conceptual engineering, extensive use is made of generic information related to the installations/facilities being assessed. Hazard identification is based on the NEERI experience, having undertaken many hazard identification studies for onshore field developments.

The HAZID records are detailed in **Table 3.1**. The table details a range of typical hazards on each of the field facilities. Hazards are identified in terms of safety and/or

environmental impact. The table provides a brief assessment of each identified hazard and identifies if the hazard is specifically taken forward for consequence analysis.

It is noted that some hazards are incorporated within other hazards. In such cases hazards, which are incorporated elsewhere, are not flagged as being specifically included within the analysis.

Table 3.1
Hazard Identification Summary

Facility	Hazard	Analysis
Aishwariya & Mangala Fields		
Well Aishwariya (oil)	Blowout	Yes
Well Mangala (oil)	Blowout	Yes
Well (gas)	Blowout	Yes
GGs	Leakage in upstream of Choke	Yes
GGs	Leakage in downstream of Choke	Yes
GGs	Leakage in downstream of oil Heater	Yes
GGs	HP Separator (gas & oil)	Yes
GGs	LP Separator (gas & oil)	Yes
GGs	Leakage in gas well flow line	Yes
GGs	Leakage in gas lift Compressor	Yes
GGs	Leakage in pipeline of stabilized oil	Yes
GGs	Buffer Tank (leakage, rupture & tank on fire)	Yes
CTF	Booster pump (leakage)	Yes
CTF	Crude storage tank (leakage, rupture & tank on fire)	Yes
CTF	Diluent storage tank (leakage, rupture & tank on fire)	Yes
GGs & CTF	Leakage in outlet of furnace of upgradation unit	Yes
Rageshwari Gas Fields		
Well Rageshwari	Blowout (gas)	Yes
GGs	Leakage in upstream of Choke	Yes
GGs	Leakage in downstream of Choke	Yes
GGs	Leakage in downstream of oil Heater	Yes
GGs	Leakage in inlet of Separator	Yes
GGs	Leakage in inlet pipeline to Compressor	Yes
GGs	Leakage in outlet pipeline form Compressor to Manifold	Yes
GGs	Leakage in pipeline to Metering Package	Yes
CPP	Leakage in pipeline to CPP	Yes
CPP	Gas pipeline (76 km)	Yes

Power Plant (Gas)		
Power Plant	Gas pipeline	Yes
Power Plant	Leakage in pipeline to Compressor	Yes
Power Plant	Leakage in outlet pipeline from Compressor	Yes
Power Plant (Crude)		
Power Plant	Booster pump	Yes
Power Plant	Crude day tank (leakage and rupture)	Yes
Saraswati and Rageshwari Fields		
Well	Blowout (oil)	Yes
GGs	Leakage in upstream of Choke	Yes
GGs	Leakage in downstream of Choke	Yes
GGs	Leakage in downstream of oil Heater	Yes
GGs	HP Separator (gas)	Yes
GGs	LP Separator (oil & gas)	Yes
GGs	Leakage in pipeline to GGS	Yes
GGs	Leakage in pipeline to 3 phase Separator	Yes
GGs	Leakage in pipeline to Desalter Train	Yes
GGs	Leakage in pipeline to common CTF	Yes
GGs	Buffer Tank (leakage, rupture & tank on fire)	Yes
CTF	Crude storage tank (leakage, rupture & tank on fire)	Yes
CTF	Tankers (20kl & 12kl)	Yes

3.5 Consequence Analysis

Quantification of the damage can be done by means of various models, which can then be translated in terms of injuries and damage to the exposed population and buildings. Oil and gas may be released and result into jet fire & less likely unconfined vapour cloud explosion causing possible damage to the surrounding areas. Extent of the damage depends upon the nature of release. The release of flammable material and subsequent ignition results in heat radiation, pressure wave or vapour cloud depending upon the flammability and its physical state.

It is important to visualise the consequence of the release of such substances and the damage caused to the surrounding areas. An insight into physical effects resulting from the release of hazardous substances can be had by means of various models.

3.5.1 Factors influencing the use of Physical Effect Models

In order to calculate the physical effects of accidental releases of hazardous substances, following steps must be carried out in succession:

- ◆ Determining the form in which the hazardous substances occur e.g. gas, gas condensed to liquid or as a liquid in equilibrium with vapour
- ◆ Determination of the way in which the release takes place; for example intermittent or continuous release
- ◆ Determination of the outflow volume (as a function of time) of the gas, vapour or liquid. In the event of liquid outflow, possible two-phase outflow and the determination of the evaporation from any pool of liquid formed
- ◆ Dispersion of the released gas or vapour which has formed into the atmosphere
- ◆ In case of flammable substances, the heat radiation is computed for the following scenarios:
 - Torch, if vapours are ignited
 - Pool fire, if pool of liquid is ignited
 - Boiling Liquid Expanding Vapour Explosion (BLEVE)
 - Vapour Cloud Explosion and Flash Fire Envelope

In the distribution model, account is taken of the atmospheric stability, the so-called Pasquill classes (A to F) and a wind velocity. The model is based on a point source. In practice, however, a point source will never exist; for example surface source in case of pools. Further, account should be taken of the nature of the release. For example, vapour may be released in a continuous manner in the form of a jet.

3.6 Scenario Identification

3.6.1 Release of Gas or Oil

Release of crude oil and natural gas can cause hazard to the environment. **Fig. 3.1** provides a flowchart that can be followed to evaluate the consequences of the release of a flammable or toxic chemical. This chart is general in nature and not all of the events in the chart may be applicable to crude oil and natural gas. However, it provides a useful guide for the steps involved in scenario generation.

This section addresses the application of a general approach to oil and natural gas facility. Firstly, it should be noted that natural gas is less reactive than other common hydrocarbon fuels. Hence, it is less likely to be involved in a serious vapour cloud explosion,

especially under unconfined conditions. Crude oil on the other hand can cause pool fire on spillage and subsequent ignition.

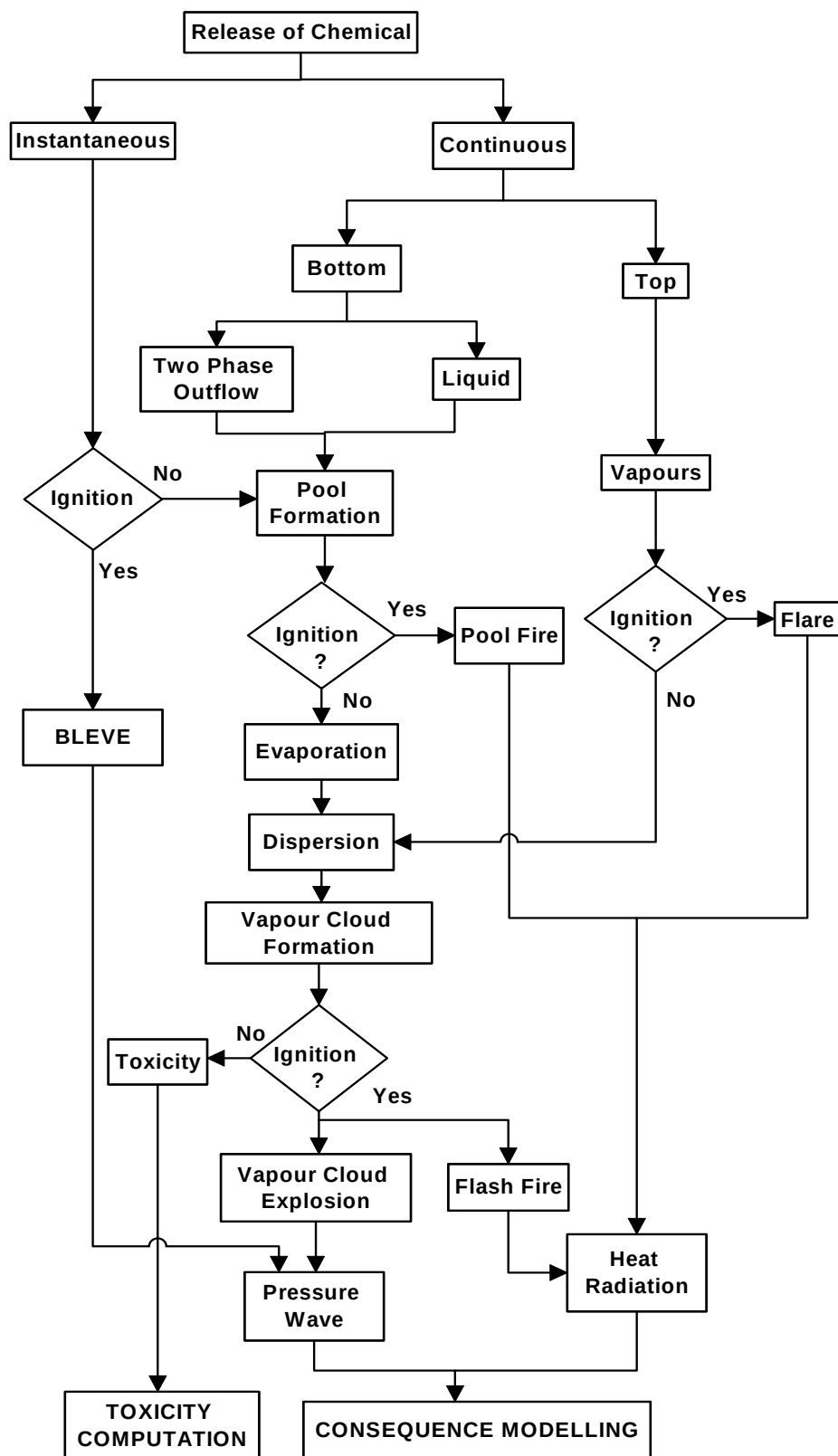


Fig. 3.1: Accidental Release of Chemicals: A Scenario

3.6.2 Failure Case Listing

The hazards posed by the oil and natural gas wells are the same as those posed by any gas well carrying high methane content in natural gas. Historical evidence demonstrates that although unlikely, the most significant hazard arises from the thermal radiation produced by an ignited liquid or gas release. Releases from the wells could arise in the form of blowouts, whereas releases from the pipelines and Gas Processing equipments can occur due to leaks. This may lead to release of gas into the atmosphere or an oil spill. An availability of ignition source can lead to jet fire, pool fire, and flash fire or vapour cloud explosion.

3.6.3 Models for the Calculation of Heat Loads and Shock Waves

If a flammable gas or liquid is released, damage resulting from heat radiation or explosion may occur on ignition. The models used in this study for the effects in the event of immediate ignition (torch and pool fire) and ignition of a gas cloud will be discussed in succession. These models calculate the heat radiation or peak overpressure as a function of the distance from the torch, the ignited pool or gas cloud. (Table 3.2, 3.3 and 3.4).

Table 3.2

Damage Criteria in kW/m² for Heat Load

Exposure time	t = 10 seconds		t = 30 seconds		t = 60 seconds	
	With protection	Without protection	With protection	Without protection	With protection	Without protection
1% lethal injury	21.2	16.5	9.3	7.3	5.5	4.3
First degree burns	8.5	6.9	4.0	3.0	2.2	1.8

Table 3.3

Damage Criteria for a Pressure Wave

Peak Overpressure (bar)	Type of Damage
0.30	90% of houses seriously damaged
0.10	10% of houses seriously damaged
0.03	Damage by flying fragments of glass
0.01	Windows smashed

Table 3.4

Damage Caused at Various Heat Loads

Heat Load (kW/m ²)	Type of Damage
37.5	Sufficient to cause damage to process equipment
25.0	Minimum energy required to ignite wood infinitely long exposure (non-piloted)
16.5	1% lethality, if exposed for 10 seconds
12.5	Minimum energy required for piloted ignition of wood, melting plastic tubing
6.9	First degree burns if exposed for 10 seconds
4.0	Sufficient to cause pain to personnel if unable to reach over within 20 seconds; however, blistering of skin (1 st degree burns) is likely
1.6	Will cause no discomfort to long exposures

3.6.4 Burning Torch (Flare)

Humidity of the air (water vapour) has a relatively high heat-absorbing capacity. The orientation (horizontal / vertical) of the object irradiated with respect to the fire is an important factor to be considered. If a jetted release of the oil & gas mixture is ignited, a stable diffusion torch or jet fire may be produced. This study uses a model with which, the length of torch and the thermal load for the surrounding area can be calculated. For the flammable gas, in this model, an ellipse is assumed for the shape of a torch. The volume of the (torch) flare in this model is related to the outflow. In order to calculate the thermal load, the centre of the flare is regarded as a point source. This centre is taken as being half a flare-length from the point of outflow.

3.6.5 Pool Fire

Release of crude oil due to leak in storage tank may lead to formation of a pool. An availability of ignition may cause pool fire. The pool radius is related to outflow rate. Evaporation model is also considered during calculations. Pool surface is considered and damage is calculated for the surroundings in terms of the heat load.

3.6.6 Flash Fire Envelope

A flash fire is the non-explosive combustion of vapour cloud resulting from release of a flammable material in the atmosphere, which after mixing with air, ignites. A flash fire results from the ignition of a released flammable cloud, in which there is essentially no increase in combustion rate. The ignition source could be electric spark, a hot surface, and friction between moving parts of a machine or an open fire.

Part of the reason for flash fire is that flammable fuels have a vapour temperature

less than ambient temperature. Hence as a result of spill, they are dispersed initially by the negative buoyancy of the cold vapours and subsequently by atmospheric turbulence. After the release and dispersion of a flammable fuel, the resulting vapour cloud is ignited and when the fuel vapour is not mixed with sufficient air prior to ignition, it results in the diffusion fire burning. Therefore, the rate at which the fuel vapour and air are mixed together during combustion determines the rate of burning in the flash fire.

The main dangers of flash fires are radiation and direct flame contact. The size of the flammable cloud determines the area of possible direct flame contact effects. Radiation effects on a target depend on several factors including its distance from the flames, flame height, flame emissive power, local atmospheric transitivity and cloud size. Most of the time, flash combustion of a flash lasts for no more than a few seconds

3.6.7 Vapour Cloud Explosion

Vapour Cloud Explosions begin with a release of a large quantity of a flammable vaporising liquid or gas from a storage tank, transport vessel or pipeline producing a dangerous overpressure wave. These explosions follow a well-determined pattern. There are basically following four features, which must be present for an effective vapour cloud explosion to occur with an effective blast :

- ◆ The released material must be flammable and at a suitable condition of temperature and pressure, which depends on the chemical. The materials which come under this category range from liquefied gases under pressure (e.g. butane, propane); ordinary flammable liquids (e.g. cyclohexane, naphtha) to non-liquefied flammable gases (e.g. ethylene, acetylene)
- ◆ Before the ignition, a cloud of sufficient size must have been formed. Normally, ignition delays of a few minutes are considered the most probable for generating the vapour cloud explosions
- ◆ A sufficient amount of the cloud must be within the flammable range of the material to cause extensive overpressure
- ◆ The flame speed determines the blast effects of the vapour cloud explosions, which can vary greatly and depends upon the confinement.

The flammable content of a gas cloud is calculated by three-dimensional integration of the concentration profiles, which fall within the flammable limits. If the gas cloud ignites, two situations can occur, namely non-explosive combustion (flash fire) and

explosive combustion (flash fire + explosion). The unconfined gas cloud of methane normally leads to a flash fire.

3.7 Injuries to Human Population

3.7.1 Vulnerability Models

Vulnerability models are used in order to determine how people are injured by exposure to a heat load or pressure wave. Such models are designed on the basis of animal experiments or on the basis of the analysis of injuries resulting from accidents, which have occurred. Vulnerability models often make use of a probit function. In a probit function, a link is made between the load and percentage of the people exposed to a particular type of injury. It is represented as follows:

$$Pr = k_1 + k_2 \ln (V)$$

In which,

Pr = Probit function; the measure of the percentage of people exposed to a particular injury

K_1 = a constant depending on the type of injury and type of load

K_2 = a constant depending on the type of load

V = load

The response percentage is plotted on the left and the probit linearly on the right; the S-shaped curve belongs to the left-hand axis and the straight line to the right-hand axis.

In the following sections, vulnerability models are given for heat radiation making use of probit functions.

3.7.2 Health Injuries Resulting from Flammable Liquids and Gases

In case of flammable gases or liquids, on immediate ignition, a jet fire or pool fire will occur. The injuries in this case are mainly caused by heat radiation.

If the gas is not ignited immediately, it will disperse into the atmosphere. While if the gas cloud ignites, it is assumed that everyone present within the gas cloud will die as a result of burns or asphyxiation. Outside the gas cloud, the duration of thermal load will be too brief to cause injuries. In the event of very rapid combustion of gas cloud, the shock wave may cause damage outside the limits of the cloud. Explosive combustion will only occur if the cloud is enclosed to some extent between buildings and obstacles.

3.7.3 Damage Models for Heat Radiation

It is assumed that everyone inside the area covered will be burnt to death or will asphyxiate. Following probit functions are the examples of methods, which can be used to calculate the percentage of lethality, and first-degree burns that will occur at a particular thermal load and period of exposure of an unprotected body.

Lethality,

$$Pr = -36.38 + 2.56 \ln (t.q.^{4/3})$$

First degree burn symptoms

$$Pr = -39.83 + 3.0186 \ln (t.q.^{4/3})$$

In which,

t = exposure time in seconds

q = thermal load W/m²

Pr = probit, which can be converted to a percentage of exposed persons who incur the symptoms mentioned

For 1% lethality in the exposed persons the corresponding probit value is 2.67.

It is sometimes assumed that injuries will be reduced by a factor of 7 if people are wearing protective clothes.

Following values have been chosen for the exposure time to heat radiation :

- ◆ 10 sec. for exposed persons in a populated area. It is assumed that they will find protection from the heat radiation (e.g. a wall) within 10 min.
- ◆ 30 sec. this pessimistic assumption applies if people do not run away immediately or when no protection is available

3.7.4 Damage Models for Pressure Wave

A pressure wave can be caused by gas cloud explosion. Following damage criteria are assumed as a result of the peak overpressure of a pressure wave:

- ◆ Bar wave is taken as the limit for fatal injury
- ◆ 0.03 bar overpressure wave is taken as the limit for occurrence of wounds due to flying glass fragments

The following assumptions are used to translate an explosion in terms of damage to the surrounding area as indicated in **Table 3.3** above:

- ◆ Within the contour area of the exploding gas cloud, everyone will die as a result of burns or asphyxiation. Houses and buildings in this zone will be severely damaged
- ◆ In houses with serious damage, it is assumed that one out of eight persons present will be killed as a result of building collapse. Within the zone of a peak overpressure of 0.3 bar, the risk of death in houses is $0.9 \times 1/8 = 0.1125$, and in the zone with a peak overpressure of 0.1 bar, probability of death is $0.1 \times 1/8 = 0.0125$ i.e. one in eighty people will be killed.

3.8 Input Data

The data used for the consequence analysis is depicted in **Table 3.5**:

Table 3.5

Input Data for Consequence Analysis

Parameter	Case
Ambient Temperature	35 ⁰ C
Atmospheric stability	A & D
Relative humidity	70%
Wind speed	2 m/s for stability class A 5 m/s for stability class D

3.9 Oil and Gas Composition

The composition of stabilized oil at Mangala field is depicted in **Table 3.6**.

Table 3.6

Stabilized Oil Composition North Fields-Mangala

Components	Mol Fraction
Nitrogen	0.0000
CO ₂	0.0043
H ₂ S	0.0000
Methane	0.0033
Ethane	0.0001
Propane	0.0006

i-Butane	0.0003
n-Butane	0.0013
i-Pentane	0.0018
n-Hexane	0.0045
PsdC7H16*	0.0121
PsdC8H18*	0.0222
PsdC9H20*	0.0223
PsdC10H22*	0.0221
PsdC11H24*	0.0211
PsdC12H26*	0.0229
PsdC13H28*	0.0241
PsdC14H30*	0.0257
PsdC15H32*	0.0286
PsdC16H34*	0.0250
PsdC17H36*	0.0221
Components	Mol Fraction
PsdC18H38*	0.0264
PsdC19H40*	0.0254
PsdC20H42*	0.0213
PsdC21H46*	0.0213
PsdC22H48*	0.0201
PsdC23H50*	0.0213
PsdC24H52*	0.0200
PsdC25H54*	0.0205
PsdC26H56*	0.0194
PsdC27H58*	0.0205
PsdC28H60*	0.0184
PsdC29H16*	0.0205
Hypo C30+*	0.4796
H ₂ O	0.0000
Total	1.0000

The composition of flare / fuel gas at Mangala field is depicted in **Table 3.7**.

Table 3.7
Flare / Fuel Gas Composition

Components	HP Separator Gas	LP Separator Gas
	Mol Fraction	
Nitrogen	0.0000	0.0000
CO ₂	0.2420	0.3405
H ₂ S	0.0000	0.0000
Methane	0.7313	0.5709
Ethane	0.0030	0.0050
Propane	0.0059	0.0151
i-Butane	0.0012	0.0037
n-Butane	0.0041	0.0136
i-Pentane	0.0014	0.0050
n-Pentane	0.0021	0.0078
n-Hexane	0.0021	0.0082
PsdC7H16*	0.0028	0.0110
PsdC8H18*	0.0026	0.0104
PsdC9H20*	0.0012	0.0044
PsdC10H22*	0.0006	0.0020
Total	1.00	1.00
Relative gas gravity	0.84	1.07
Mol Wt	24.3	30.96

The properties of stabilized oil at Mangala field is depicted in **Table 3.8**

Table 3.8
Stabilized Oil Properties North Fields - Mangala

Std Density	873.6 Kg/m ³
Visosity (cp)	
@45° C	90 cp
@55° C	40cp
@80° C	18 cp
Wax content (wt%)	38%
BS & W	0.5%
Salt content	6ptb

The pseudo component properties of stabilized oil at Mangala field is depicted in **Table 3.9**.

Table 3.9

Pseudo Component Properties of Stabilized Oil

Pseudo Component	NBP (°C)	Mol wt	Std Density (Kg/m ³)
PsdC7H16*	95.5	96	727
PsdC8H18*	118.6	107	749
PsdC9H20*	145.6	121	768
PsdC10H22*	168.1	134	782
PsdC11H24*	184.5	147	793
PsdC12H26*	200.5	161	804
PsdC13H28*	214.09	171	815
PsdC14H30*	232.4	190	826
PsdC15H32*	252.7	206	836
PsdC16H34*	271.5	222	843
PsdC17H36*	286.6	237	851
PsdC18H38*	303.6	251	856
PsdC19H40*	316.2	263	861
PsdC20H42*	328.4	275	866
PsdC21H46*	344.1	291	871
PsdC22H48*	353.1	300	876
PsdC23H50*	364.6	312	881
PsdC24H52*	375.7	324	885
PsdC25H54*	387.3	337	888
PsdC26H56*	398	349	892
PsdC27H58*	407.8	360	896
PsdC28H60*	418.1	372	899
PsdC29H16*	426.6	382	902
Hypo C30+*	608.6	655	898

The composition of stabilized oil at Saraswati field is depicted in **Table 3.10**

Table 3.10

Stabilized Oil composition Saraswati field

Components	Mol Fraction
Nitrogen	0.0001
CO ₂	0.0002
H ₂ S	0.0000
Methane	0.0007
Ethane	0.0023
Propane	0.0097
i-Butane	0.0115
n-Butane	0.0178
i-Pentane	0.02
n-Pentane	0.0236
n-Hexane	0.0636
n-Heptane	0.0883
n-Octane	0.1321
n-Nonane	0.1023
n-Decane	0.0795
n-C11	0.0638
n-C12	0.0408
n-C13	0.0499
n-C14	0.0381
n-C15	0.0387
n-C16	0.0274
n-C17	0.029
n-C18	0.0203
n-C19	0.167
n-C20	0.0151
n-C21	0.0142
n-C22	0.0134
n-C23	0.0123
n-C24	0.0111
n-C25	0.0104
n-C26	0.0088
n-C27	0.0079
n-C28	0.0064
n-C29	0.0055
Hypo C30+*	0.0185
Total	1.0000

The composition of flare / fuel gas at Saraswati field is depicted in **Table 3.11**.

Table 3.11

Flare / Fuel Gas Composition Saraswati Field

	HP Separator Gas	LP Separator Gas
Components	Mol Fraction	
Nitrogen	0.1721	0.0269
CO ₂	0.0243	0.0156
H ₂ S	0.0000	0.0000
Methane	0.4156	0.1387
Ethane	0.1202	0.1168
Propane	0.1013	0.1871
i-Butane	0.0410	0.1059
n-Butane	0.0459	0.1285
i-Pentane	0.0205	0.1068
n-Pentane	0.0193	0.066
n-Hexane	0.0191	0.0705
n-Heptane	0.0106	0.0398
n-Octane	0.0066	0.0244
n-Nonane	0.0022	0.0079
n-Decane	0.0007	0.0026
Total	1.00	1.00
Relative gas gravity	1.12	1.84
Mol Wt	32.5	53.2

The composition of flare / fuel gas at Rageshwari field is depicted in **Table 3.12**.

Table 3.12

Flare / Fuel Gas Composition - Rageshwari

Components	Mol %
H ₂	0.01
CO ₂	0
H ₂ S	0
N ₂	0.22
Methane	81.21
Ethane	10.94
Propane	3.34
i-Butane	1.51
n-Butane	1.02
i-Pentane	0.55
neo-pentane	0.43
n-Hexane	0.43
Methylcyclopentane	0.01
Benzene	0.04
Cyclohexane	0.1
Heptanes	0.15
Methylcyclohexane	0.01
Toulene	0.02
Octanes	0.05
Ethylbenzene	0
M-P-Xylene	0
O-Xylene	0
Nonanes	0.02
1,2,4 Trimethyl BZ	0
Decane Plus	0.01
Total	100
Relative gas gravity	0.716
Molecular Wt	20.14

The properties of stabilized oil at Saraswati & Rageshwari field is depicted in Table 3.13.

Table 3.13

Stabilized Oil Properties at Saraswati & Rageshwari

Std Density	753.1-812.5 Kg/m ³
Visosity (cp)	
@40° C	11.71 cst
@60° C	3.54cst
Wax content (wt%)	31.8
BS & W	0.5%
Salt content	6ptb

The pseudo component properties of stabilized oil at Saraswati & Rageshwari field is depicted in **Table 3.14**.

Table 3.14

Pseudo Component Properties of Stabilized Oil at Saraswati & Rageshwari

Pseudo Component	NBP (°C)	Mol wt	Std Density (Kg/m ³)
HypoC30 + _1*	473.665	450	889.207

Composition of well fluid at Rageshwari gas field is depicted in **Table 3.15**.

Table 3.15

Composition of Well Fluid at Rageshwari Gas Field

Components	Mol %
CO2	0
H2S	0.0
N2	0.22
Methane	81.22
Ethane	10.94
Propane	3.34
i-Butane	1.51
n-Butane	1.02
i-Pentane	0.56
n-Pentane	0.43
n-Hexane	0.49
n-Heptane	0.19
n-Octanae	0.05
n-Nonane	0.02
n-Decane	0.01
Total	100
Relative Gas Gravity (air=1)	0.7159
Molecular wt	20.74
Gross Heating Value	1260.8 Btu / scf
Net Heating Value	1143.5 Btu / scf

3.10 Results and Discussions

Following scenarios are visualised for carrying out the consequence analysis for the release of oil and gas from Aishwariya and Mangla Field: Leakages may be due to small puncture in pipeline, leakages in valves, flanges, joints, bends etc.

- ◆ Well Aishwariya (Oil) Blowout
- ◆ Well Mangla (Oil) Blowout
- ◆ Well Aishwariya and Mangla (Gas) Blowout
- ◆ Leakage in Upstream of Choke (well fluid)
- ◆ Leakage in Downstream of Choke (well fluid)
- ◆ Leakage in Downstream of Oil Heater (Well Fluid)
- ◆ Leakage in HP Separator Gas outlet
- ◆ Leakage in outlet of LP Compressor Unit
- ◆ Leakage in HP separator oil outlet
- ◆ Leakage in LP separator oil outlet
- ◆ Leakage in LP separator gas outlet
- ◆ Leakage in Gas Well flow line
- ◆ Leakage in Gas lift Compressor outlet
- ◆ Leakage in Stabilized Oil from GGS
- ◆ Booster pump failure
- ◆ Leakage in Oil Buffer Tank
- ◆ Rupture of Oil Buffer Tank
- ◆ Oil Buffer Tank on fire
- ◆ Leakage in Oil storage Tank at CTF
- ◆ Rupture of 2 Oil storage Tank at CTF
- ◆ Oil storage tank at CTF on fire
- ◆ Leakage in diluent storage tank at CTF
- ◆ Rupture of Diluent Storage Tank at CTF
- ◆ Leakage in outlet of furnace of oil upgradation unit at GGS & CTF

Case 1: Well Aishwariya (Oil) Blowout

Jet Fire

A well blow out can lead to uncontrolled release of oil into the atmosphere and a subsequent jet fire could result on availability of an immediate ignition source. Heat load generated by the flame depends upon the mass flow rate of the released material. Generally, 30 persons are working in the drilling area, which could be exposed to the heat load in case of well blow out.

Damage distances are computed for the operating pressure of 290 psi and temperature of 70°C. Weather conditions 2A and 5D are considered while computing the damage distances. The damage distance of 95.7m is obtained for the heat load of 4 kW/m² in case of well blow out for 5D conditions. Results are shown in **Table 3.16**.

Case 2: Well Mangla (Oil) Blowout

Jet Fire

A well blow out can lead to uncontrolled release of oil into the atmosphere and a subsequent jet fire could result on availability of an immediate ignition source. Heat load generated by the flame depends upon the mass flow rate of the released material. Generally, 30 persons are working in the drilling area, which could be exposed to the heat load in case of well blow out.

Damage distances are computed for the operating pressure of 290 psi and temperature of 70°C. Weather conditions 2A and 5D are considered while computing the damage distances. The damage distance of 95.7m is obtained for the heat load of 4 kW/m² in case of well blow out for 5D conditions. Results are shown in **Table 3.16**.

Case 3: Well Aishwariya and Mangla (Gas) Blowout

Jet Fire

A well blow out can lead to uncontrolled release of gas into the atmosphere and a subsequent jet fire could result on availability of an immediate ignition source. Heat load generated by the flame depends upon the mass flow rate of the released material. Generally, 30 persons are working in the drilling area, which could be exposed to the heat load in case of well blow out.

Damage distances are computed for the operating pressure of 1600 psi and temperature of 70°C. Weather conditions 2A and 5D are considered while computing the

damage distances. The damage distance of 44.1m is obtained for the heat load of 4 kW/m² in case of well blow out for 5D conditions. Results are shown in **Table 3.16**.

Case 4: Leakages in Upstream of Choke (well fluid)

Jet Fire

Leakages in Upstream of Choke (well fluid) can lead to uncontrolled release of well fluid into the atmosphere and a subsequent jet fire could result on availability of an immediate ignition source. Heat load generated by the flame depends upon the mass flow rate of the released material.

Damage distances are computed for the operating pressure of 160 psi and temperature of 66°C. Weather conditions 2A and 5D for 5 mm and 25 mm leak are considered while computing the damage distances. The damage distance of 29.3 m is obtained for the heat load of 4 kW/m² in case of 5 mm leak and 122.8 m for 25 mm leak for 5D conditions. Similarly the distances for 12.5 kW/m² showed in **Table 3.16**.

Pool Fire

Accidental release of well fluid can lead to oil spill and subsequent formation of pool. This pool, if gets ignition may result into pool fire. Stability class of 2A and 5D are considered while computing the damage distances.

The damage distance of 20.8 m is obtained for the heat load of 4 kW/m² for 5mm leak and 80.1mm for 25mm leak of pipeline for 5D conditions. Similarly the distances for 12.5 kW/m² and 37.5 kW/m² are depicted in **Table 3.17**.

Case 5: Leakage in downstream of choke (well fluid)

Jet Fire

Scenarios are considered for 5 mm and 25mm leaks in the downstream of choke (well fluid). This can lead to release of well fluid into the atmosphere in the form of jet, which may result into jet fire on availability of an immediate ignition. Damage distances are computed for the operating pressure of 130 psi and temperature of 47°C. Stability classes A and D and wind speeds of 2m/s and 5m/s are considered while computing the damage distances.

The damage distance of 28.3 m is obtained for the heat load of 4 kW/m² for 5mm leak and 119 m for 25mm leak for 5D conditions. Similarly the distances for 12.5 kW/m² and 37.5 kW/m² are depicted in **Table 3.16**.

Pool Fire

Accidental release of well fluid can lead to oil spill and subsequent formation of pool. This pool, if gets ignition may result into pool fire. Stability class of 2A and 5D are considered while computing the damage distances.

The damage distance of 21.4 m is obtained for the heat load of 4 kW/m² for 5mm leak and 75.7 m for 25mm leak for 5D conditions. Similarly the distances for 12.5 kW/m² and 37.5 kW/m² are depicted in **Table 3.17**.

Case 6: Leakage in the downstream of Oil Heater (well fluid)

Jet Fire

Scenarios of 5 mm and 25 mm leak in the downstream of oil heater (well fluid) are considered, which may lead to release of well fluid into the atmosphere in the form of jet. This may result into jet fire on availability of an immediate ignition. Damage distances are computed for the operating pressure of 120 psi and temperature of 80°C. Stability class 2A and 5D are considered while computing the damage distances for various heat loads.

The damage distance of 27.6 m is obtained in case of 5mm leak and 116 m for 25mm leak for the heat load of 4 kW/m² for 5D conditions. Similarly the distances for 12.5 kW/m² and 37.5 kW/m² are depicted in **Table 3.16**.

Pool Fire

Accidental release of well fluid can lead to well fluid spill and subsequent formation of pool. This pool, if gets ignition may result into pool fire. Stability class of 2A and 5D are considered while computing the damage distances.

The damage distance of 21.6 m is obtained for the heat load of 4 kW/m² for 5mm leak and 76.6 m for 25mm leak of pipeline for 5D conditions. Similarly the distances for 12.5 kW/m² are depicted in **Table 3.17**.

Case 7: Leakage in the outlet of HP Separator Gas outlet

Jet Fire

Scenarios are considered for 5mm and 25mm leaks in the outlet of HP separator Gas . This can lead to release of gas into the atmosphere at high pressure in the form of jet. This may result into jet fire on availability of an immediate ignition. Damage distances are computed for the operating pressure of 67 psi and temperature of 80°C. Stability classes A

and D and wind speeds of 2m/s and 5m/s are considered while computing the damage distances.

The damage distance of 1.9 m is obtained for 5mm leak and 13.3 m for 25mm leak for the heat load of 4 kW/m² for 5D conditions. Similarly the distances for 12.5 kW/m² and 37.5 kW/m² are depicted in **Table 3.16**.

Case 8: Leakage in Outlet of LP Compressor unit (Gas)

Jet Fire

Scenarios are considered for 5mm and 25mm leaks in the outlet of Gas Compressor. This can lead to release of gas into the atmosphere at high pressure in the form of jet. This may result into jet fire on availability of an immediate ignition. Damage distances are computed for the operating pressure of 140 psi and temperature of 55° C. Stability classes A and D and wind speeds of 2m/s and 5m/s are considered while computing the damage distances.

The damage distance of 3.3 m is obtained for 5mm leak and 18.4 m for 25mm leak the heat load of 4 kW/m² for 5D conditions. Similarly the distances for 12.5 kW/m² and 37.5 kW/m² are depicted in **Table 3.16**.

Case 9: Leakage in HP Separator Oil Outlet

Jet Fire

Scenarios are considered for 5mm and 25mm leaks in the outlet of HP Separator. This can lead to release of oil into the atmosphere at high pressure in the form of jet. This may result into jet fire on availability of an immediate ignition. Damage distances are computed for the operating pressure of 5 psi and temperature of 80° C. Stability classes A and D and wind speeds of 2m/s and 5m/s are considered while computing the damage distances.

The damage distance of 14.1 m is obtained for 5mm leak and 50.8 m for 25mm leak the heat load of 4 kW/m² for 5D conditions. Similarly the distances for 12.5 kW/m² depicted in **Table 3.16**.

Pool Fire

Scenarios of 5mm and 25mm leak in the outlet of HP Separator are considered. This can lead to oil spill and subsequent formation of pool. This pool, if gets ignition may result into pool fire. Stability class 2A and 5D are considered while computing the damage distances.

The damage distance of 10.7 m is obtained for 5mm leak and 37.3 for 25mm leak the heat load of 4 kW/m² for the scenario of 5D. Similarly the distances for 12.5 kW/m² and 37.5 kW/m² are depicted in **Table 3.17**.

Case 10: Leakage in LP Separator Oil Outlet

Jet Fire

Scenarios are considered for 5mm and 25mm leaks in the oil outlet of LP Separator. This can lead to release of oil into the atmosphere at high pressure in the form of jet. This may result into jet fire on availability of an immediate ignition. Damage distances are computed for the operating pressure of 4 psi and temperature of 79°C. Stability classes A and D and wind speeds of 2m/s and 5m/s are considered while computing the damage distances.

The damage distance of 13.4 m is obtained for 5mm leak and 47.6 m for 25mm leak the heat load of 4 kW/m² for 5D conditions. Similarly the distances for 12.5 kW/m² are depicted in **Table 3.16**.

Pool Fire

Scenarios of 5mm and 25mm leak in the oil outlet of LP Separator are considered. This can lead to oil spill and subsequent formation of pool. This pool, if gets ignition may result into pool fire. Stability class 2A and 5D are considered while computing the damage distances.

The damage distance of 10.3 m is obtained for 5mm leak and 35.9 m for 25mm leak for the heat load of 4 kW/m² for the scenario of 5D. Similarly the distances for 12.5 kW/m² and 37.5 kW/m² are depicted in **Table 3.17**.

Case 11: Leakage in LP Separator Gas Outlet

Jet Fire

Scenarios are considered for 5mm and 25mm leaks in the outlet of LP Separator Gas Outlet. This can lead to release of gas into the atmosphere at high pressure in the form of jet. This may result into jet fire on availability of an immediate ignition. Damage distances are computed for the operating pressure of 4 psi and temperature of 80° C. Stability classes A and D and wind speeds of 2m/s and 5m/s are considered while computing the damage distances.

The damage distance of 6.3m is obtained for 25mm leak the heat load of 4 kW/m² for 5D conditions. Similarly the distances for 12.5 kW/m² are depicted in **Table 3.16**.

Case 12: Leakage in Gas Well Flow Line

Jet Fire

Scenarios are considered for 5mm and 25mm leaks in the Gas Well Flow Line. This can lead to release of gas into the atmosphere at high pressure in the form of jet. This may result into jet fire on availability of an immediate ignition. Damage distances are computed for the operating pressure of 400 psi and temperature of 55° C. Stability classes A and D and wind speeds of 2m/s and 5m/s are considered while computing the damage distances.

The maximum damage distance of 6.2 m is obtained for 5mm leak and 29.2 m for 25mm leak the heat load of 4 kW/m² for 5D conditions. Similarly the distances for 12.5 kW/m² and 37.5 kW/m² are depicted in **Table 3.16**.

Case 13: Leakage in Gas Lift Compressor outlet

Jet Fire

Scenarios are considered for 5mm and 25mm leaks in the outlet of Gas Lift Compressor. This can lead to release of gas into the atmosphere at high pressure in the form of jet. This may result into jet fire on availability of an immediate ignition. Damage distances are computed for the operating pressure of 800 psi and temperature of 55° C. Stability classes A and D and wind speeds of 2m/s and 5m/s are considered while computing the damage distances.

The damage distance of 8.9 m is obtained for 5mm leak and 40.2 m for 25mm leak the heat load of 4 kW/m² for 5D conditions. Similarly the distances for 12.5 kW/m² and 37.5 kW/m² are depicted in **Table 3.16**.

Case 14: Leakage in pipeline of stabilized oil from GGS

Jet Fire

Scenarios are considered for 5mm, 25mm and full bore rupture leaks in the Stabilized oil from GGS. This can lead to release of gas into the atmosphere at high pressure in the form of jet. This may result into jet fire on availability of an immediate ignition. Damage distances are computed for the operating pressure of 5 psi and temperature of 70°C. Stability classes A and D and wind speeds of 2m/s and 5m/s are considered while computing the damage distances.

The damage distance of 8 m is obtained for 5mm leak, 33.8m for 25mm leak and 211.9 m for full bore rupture for the heat load of 4 kW/m² for 5D conditions. Similarly the distances for 12.5 kW/m² and 37.5 kW/m² are depicted in **Table 3.16**.

Pool Fire

Scenarios of 5mm, 25mm and full-bore rupture in the Stabilized oil from GGS are considered. This can lead to oil spill and subsequent formation of pool. This pool, if gets ignition may result into pool fire. Stability class 2A and 5D are considered while computing the damage distances.

The damage distance of 14.1 m is obtained for 5 mm leak , 40.1 m for 25mm leak and 157.6m for the full bore rupture for the heat load of 4 kW/m² for the scenario of 5D. Similarly the distances for 12.5 kW/m² and 37.5 kW/m² are depicted in **Table 3.17**.

Case 15: Leakage in Oil Buffer Tank

Pool Fire

Scenarios of 5 mm and 25mm leak in the Oil buffer tanks are considered. This can lead to oil spill and subsequent formation of pool. This pool, if gets ignition may result into pool fire. Stability class 2A and 5D are considered while computing the damage distances for the oil storage at ambient conditions.

The damage distance of 13.9 m is obtained for 5mm leak and 43.3m for 25mm leak the heat load of 4 kW/m² for the scenario of 5D. Similarly the distances for 12.5 kW/m² and 37.5 kW/m² are depicted in **Table 3.17**.

Case 16: Rupture of Oil Buffer Tank

Pool Fire

Scenarios of rupture in the Oil buffer tanks are considered. This can lead to oil spill and subsequent formation of pool. This pool, if gets ignition may result into pool fire. Stability class 2A and 5D are considered while computing the damage distances for the oil storage at ambient conditions.

The damage distance of 52.4 m is obtained for heat load of 4 kW/m² for the scenario of 5D. Similarly the distances for 12.5 kW/m² are depicted in **Table 3.17**. Damage contour for catastrophic rupture of oil buffer tank is presented in **Fig. 3.2**.

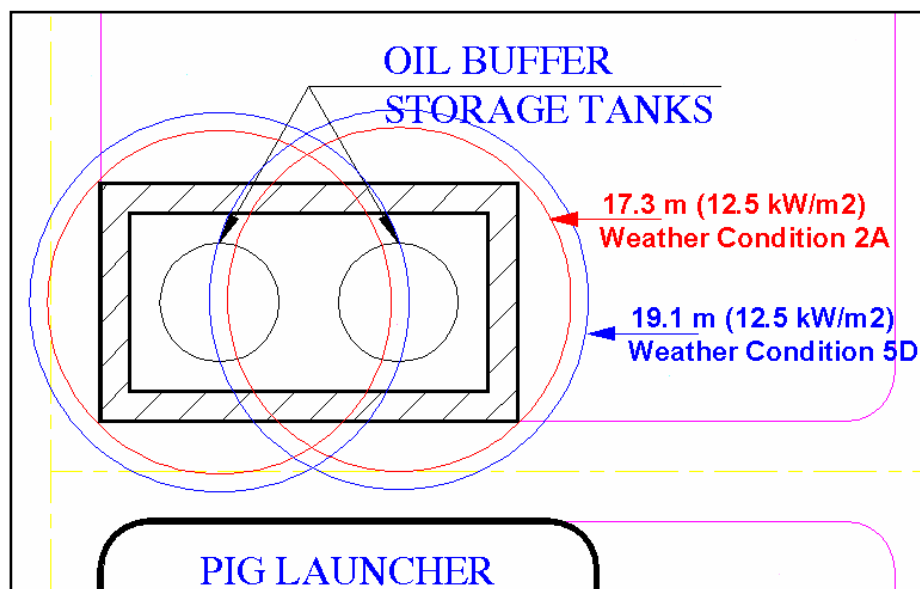


Fig. 3.2: Damage Contour for the Catastrophic Rupture of Oil Buffer Storage Tank at GGS Mangla and Aishwariya Field for the Heat Load of 12.5 kW/m^2

Case 17: Oil Buffer Tank on Fire

Pool Fire

Scenarios of Oil buffer tanks on fire are considered, which on ignition may result into tank on fire. Stability class 2A and 5D are considered while computing the damage distances for the oil storage at ambient conditions.

The damage distance of 32.6 m is obtained for heat load of 4 kW/m^2 for the scenario of 5D. Similarly the distances for 12.5 kW/m^2 are depicted in **Table 3.17**. Damage contour for oil buffer tank on fire is presented in **Fig. 3.3**.

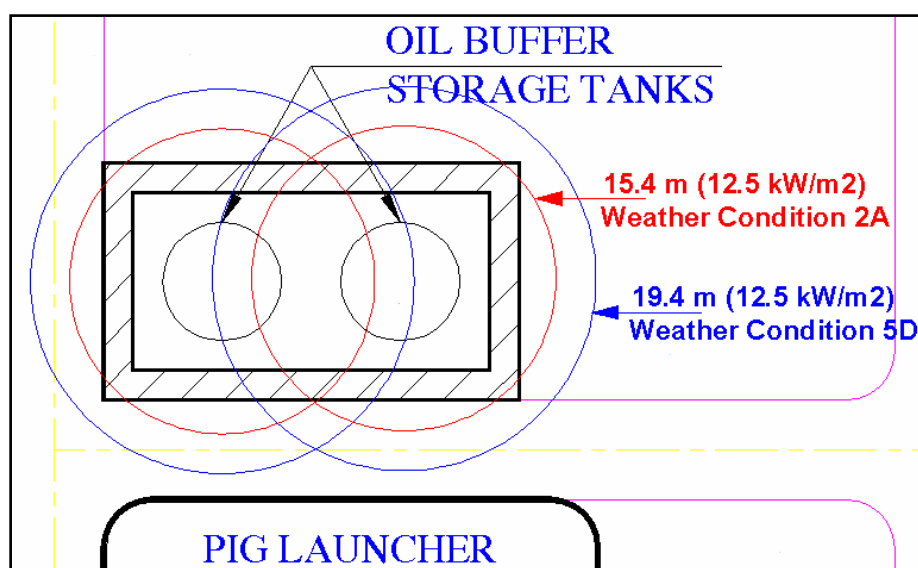


Fig. 3.3: Damage Contour for Oil Buffer Storage Tank on Fire at GGS Mangla and Aishwariya Field for the Heat Load of 12.5 kW/m^2

Case 18: Booster Pump Failure

Jet Fire

Scenarios are considered for 5mm and 25mm leaks in the booster pump. This can lead to release of gas into the atmosphere at high pressure in the form of jet. This may result into jet fire on availability of an immediate ignition. Damage distances are computed for the operating pressure of 64 psi and temperature of 110°C. Stability classes A and D and wind speeds of 2m/s and 5m/s are considered while computing the damage distances.

The damage distance of 24.4 m is obtained for 5mm leak and 100.5 m for 25mm leak for the heat load of 4 kW/m² for 5D conditions. Similarly the distances for 12.5 kW/m² are depicted in **Table 3.16**.

Pool Fire

Scenarios of 5mm and 25mm leak in the booster pump are considered. This can lead to oil spill and subsequent formation of pool. This pool, if gets ignition may result into pool fire. Stability class 2A and 5D are considered while computing the damage distances.

The damage distance of 17.5 m is obtained for 5mm leak and 58 m for 25mm leak for heat load of 4 kW/m² for the scenario of 5D. Similarly the distances for 12.5 kW/m² and 37.5 kW/m² are depicted in **Table 3.17**.

Case 19: Leakage in Oil storage tank at CTF

Pool Fire

Scenarios of 5mm and 25mm leak in the Oil storage tanks at CTF are considered. This can lead to oil spill into the dyke area and subsequent formation of pool. This pool, if gets ignition may result into pool fire. Stability class 2A and 5D are considered while computing the damage distances for the oil storage at ambient conditions.

The damage distance of 14.4 m is obtained for 5mm leak and 44.8m for 25mm leak for heat load of 4 kW/m² for the scenario of 5D. Similarly the distances for 12.5 kW/m² and 37.5 kW/m² are depicted in **Table 3.17**.

Case 20: Rupture of Oil Storage Tank at CTF

Pool Fire

Scenarios for rupture of the Oil storage tank at CTF are considered. This can lead to oil spill into the dyke area and subsequent formation of pool. This pool, if gets ignition may result into pool fire. Stability class 2A and 5D are considered while computing the damage distances for the oil storage at ambient conditions.

The damage distance of 171.2 m is obtained for heat load of 4 kW/m^2 for the scenario of 5D. Similarly the distances for 12.5 kW/m^2 are depicted in **Table 3.17**. Damage contour for catastrophic rupture of oil storage tank is presented in **Fig. 3.4**.

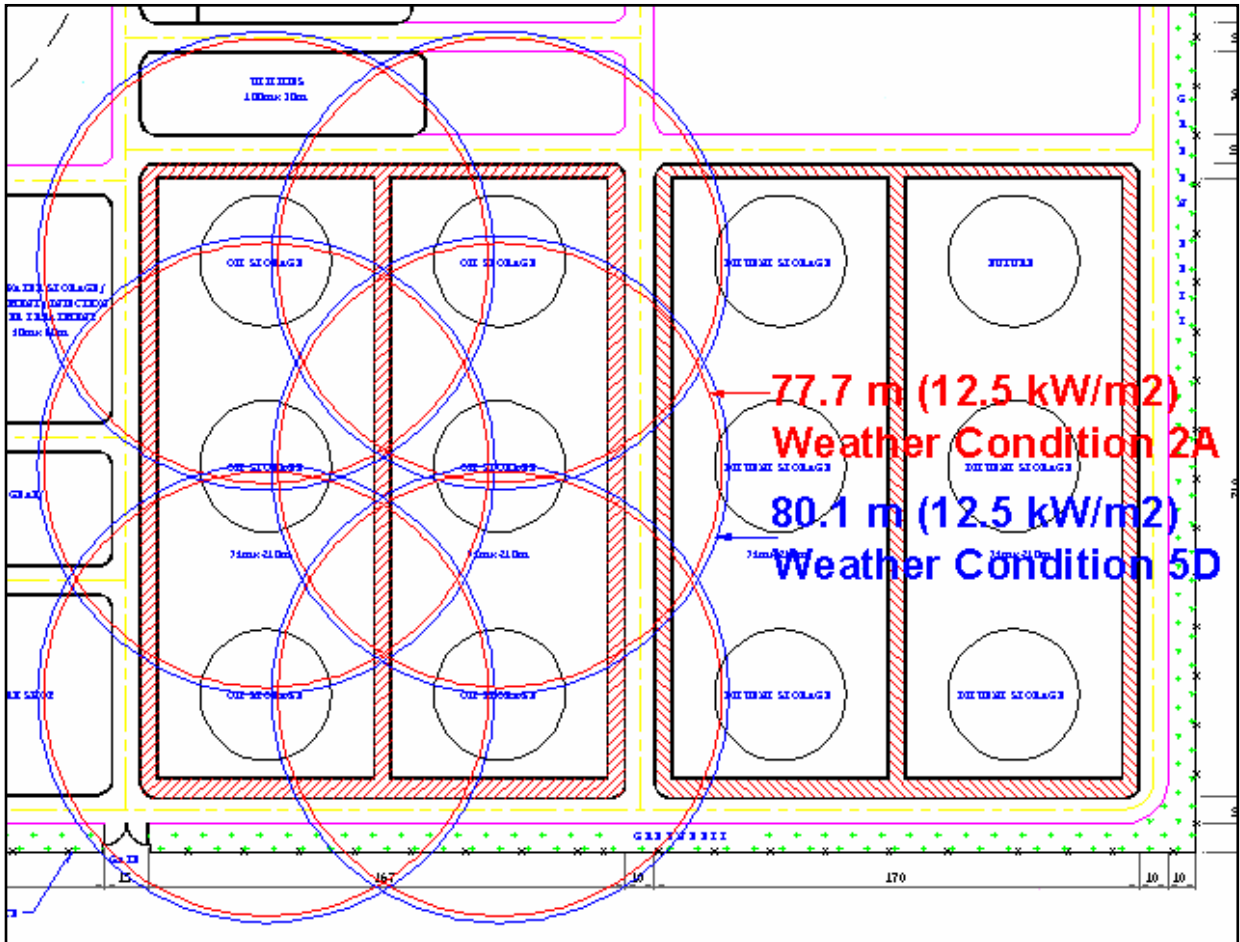


Fig. 3.4: Damage Contour for the Catastrophic Rupture of Crude Oil Storage Tank at CTF Mangla and Aishwariya Field for the Heat Load of 12.5 kW/m^2

Case 21: Rupture of 2 Oil Storage Tank at CTF at Fire

Pool Fire

Scenarios for rupture of the 2 Oil storage tank at CTF are considered. This can lead to oil spill into the dyke area and subsequent formation of pool. This pool, if gets ignition may result into pool fire. Stability class 2A and 5D are considered while computing the damage distances for the oil storage at ambient conditions.

The damage distance of 171.2 m is obtained for heat load of 4 kW/m^2 for the scenario of 5D. Similarly the distances for 12.5 kW/m^2 are depicted in **Table 3.17**.

Case 22: Oil Storage Tank at CTF on Fire

Pool Fire

Scenarios for rupture of the Oil storage tank at CTF on fire are considered. This can lead to oil spill and subsequent formation of pool. This pool, if gets ignition may result into tank on fire. Stability class 2A and 5D are considered while computing the damage distances for the oil storage at ambient conditions.

The damage distance of 69.9m is obtained for heat load of 4 kW/m^2 for the scenario of 5D. Similarly the distances for 12.5 kW/m^2 are depicted in **Table 3.17**. Damage contour for oil storage tank on fire is presented in **Fig. 3.5**.

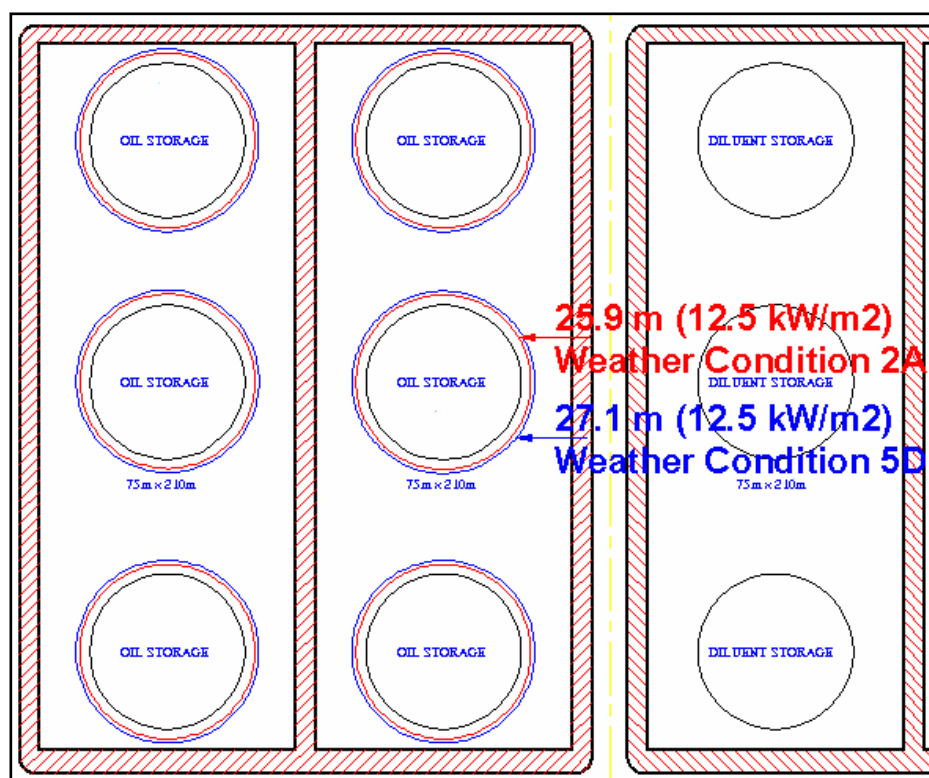


Fig. 3.5: Damage Contour for Crude Oil Storage Tank on Fire at CTF Mangla and Aishwariya Field for the Heat Load of 12.5 kW/m^2

Case 23: Leakage in Diluent Storage Tank at CTF

Pool Fire

Scenarios for leakages of the diluent storage tank at CTF are considered. This can lead to liquid release into the dyke area and subsequent formation of pool. This pool, if gets ignition may result into pool fire. Stability class 2A and 5D are considered while computing the damage distances for the oil storage at ambient conditions.

The damage distance of 19.1 m for 5 mm and 42.9 m for 25mm leak is obtained for heat load of 4.0 kW/m² for the scenario of 5D. Similarly the distances for 12.5 kW/m² and kW/m² are depicted in **Table 3.17**.

Case 24: Rupture of Diluent Storage Tank at CTF

Pool Fire

Scenarios for rupture of the diluent storage tank at CTF are considered. This can lead to liquid spill into the dyke area and subsequent formation of pool. This pool, if gets ignition may result into pool fire. Stability class 2A and 5D are considered while computing the damage distances for the oil storage at ambient conditions.

The damage distance of 157.4 m is obtained for heat load of 4 kW/m² for the scenario of 5D. Similarly the distances for 12.5 kW/m² are depicted in **Table 3.17**. Damage contour for catastrophic rupture of diluent storage tank is presented in **Fig. 3.6**.

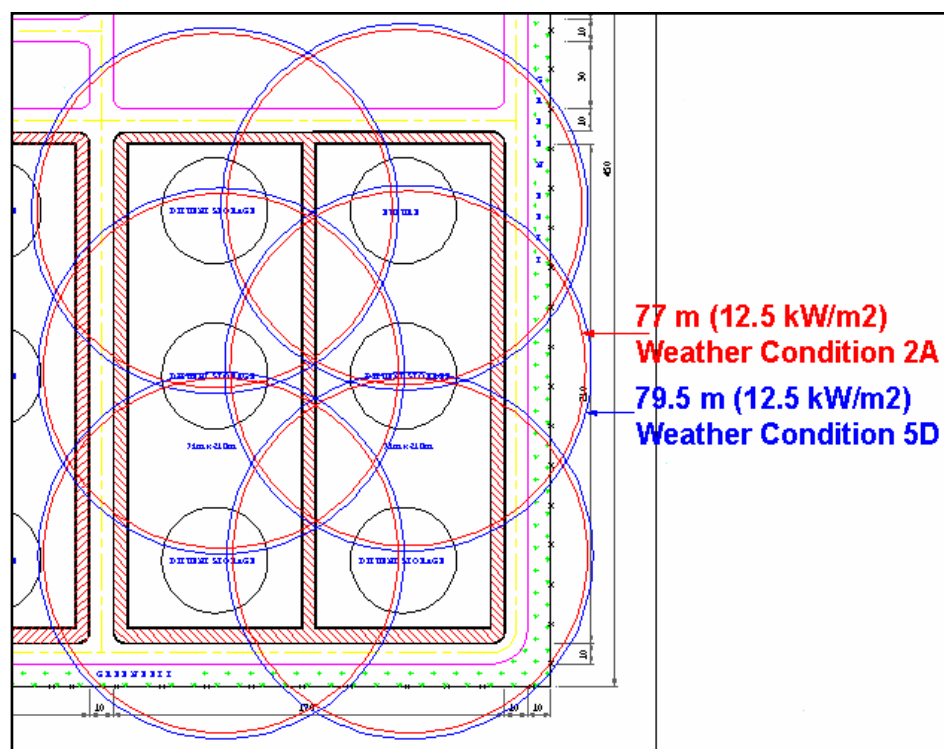


Fig. 3.6: Damage Contour for the Catastrophic Rupture of Diluent Storage Tank at CTF Mangla and Aishwariya Field for the Heat Load of 12.5 kW/m²

Case 25: Leakages in Outlet of Furnace of Oil Upgradation Unit at GGS & CTF

Jet Fire

Scenarios are considered for 5mm and 25mm leaks in the outlet of furnace. This can lead to release of pressurised liquid into the atmosphere at high pressure in the form of

jet. This may result into jet fire on availability of an immediate ignition. Damage distances are computed for the operating pressure of 217 psi and temperature of 415°C. Stability classes A and D and wind speeds of 2m/s and 5m/s are considered while computing the damage distances.

The damage distance of 19.6m is obtained for 5mm leak and 82.9m for 25mm leak for the heat load of 4.0 kW/m² for 5D conditions. Similarly the distances for 37.5 & 12.5 kW/m² are depicted in **Table 3.16**.

Similarly consequence analyses were carried out for Rageshwari gas fields, Power plant and Saraswati and Rageshwari oil fields and the results are depicted in **Tables 3.16 & 3.17**. Similarly Damage contour for catastrophic rupture / tank on fire of oil storage tank at GGS / CTF Saraswati field is presented in **Fig 3.7 to 3.10** and Damage contour for catastrophic rupture of Crude oil storage tank at Power Plant is presented in **Fig. 3.11**.

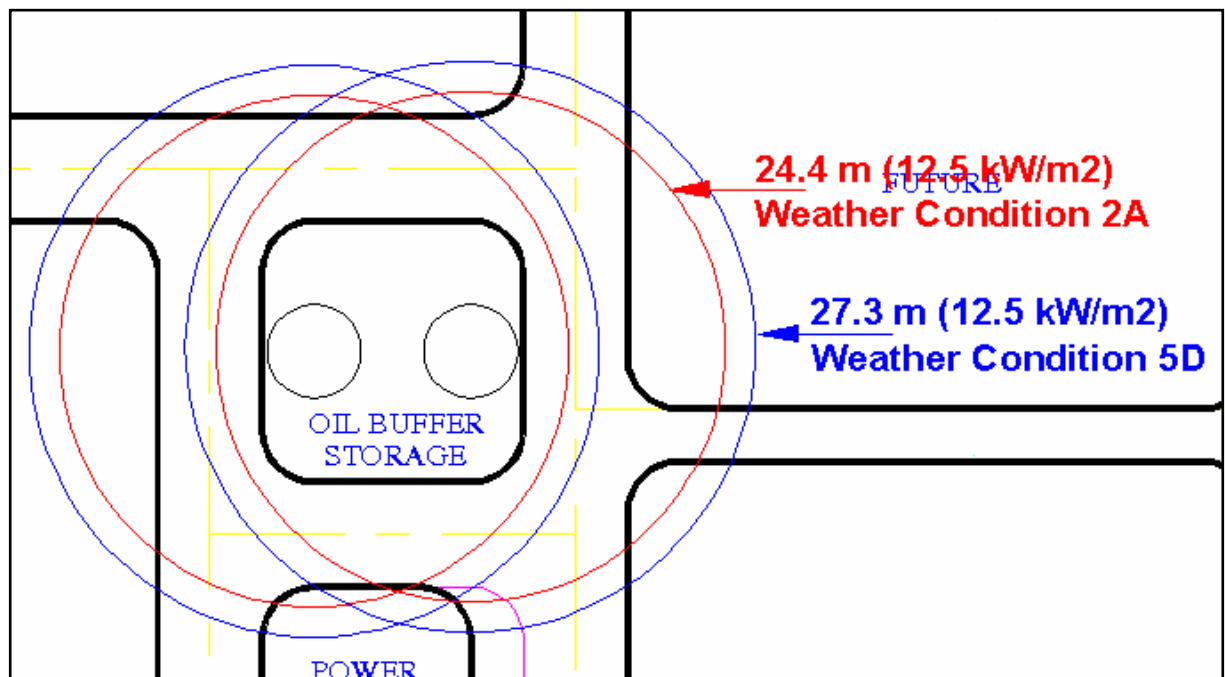


Fig. 3.7: Damage Contour for the Catastrophic Rupture of Oil Buffer Storage Tank at GGS CTF Saraswati Field for the Heat Load of 12.5 kW/m²

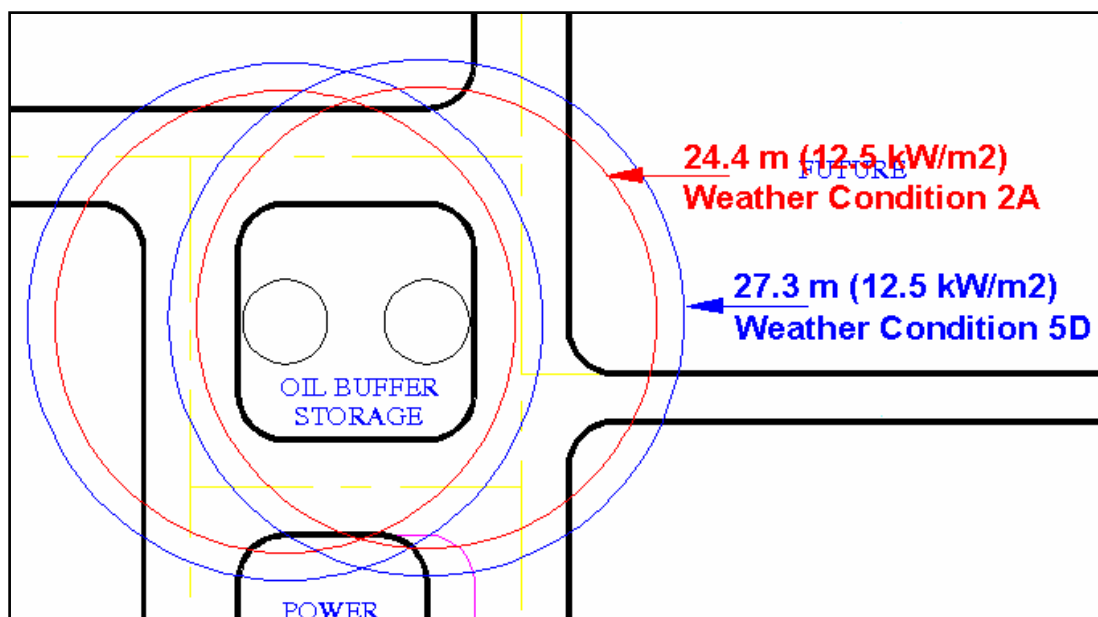


Fig. 3.8: Damage Contour for Oil Buffer Storage Tank on Fire at GGS CTF Saraswati Field for the Heat Load of 12.5 kW/m²

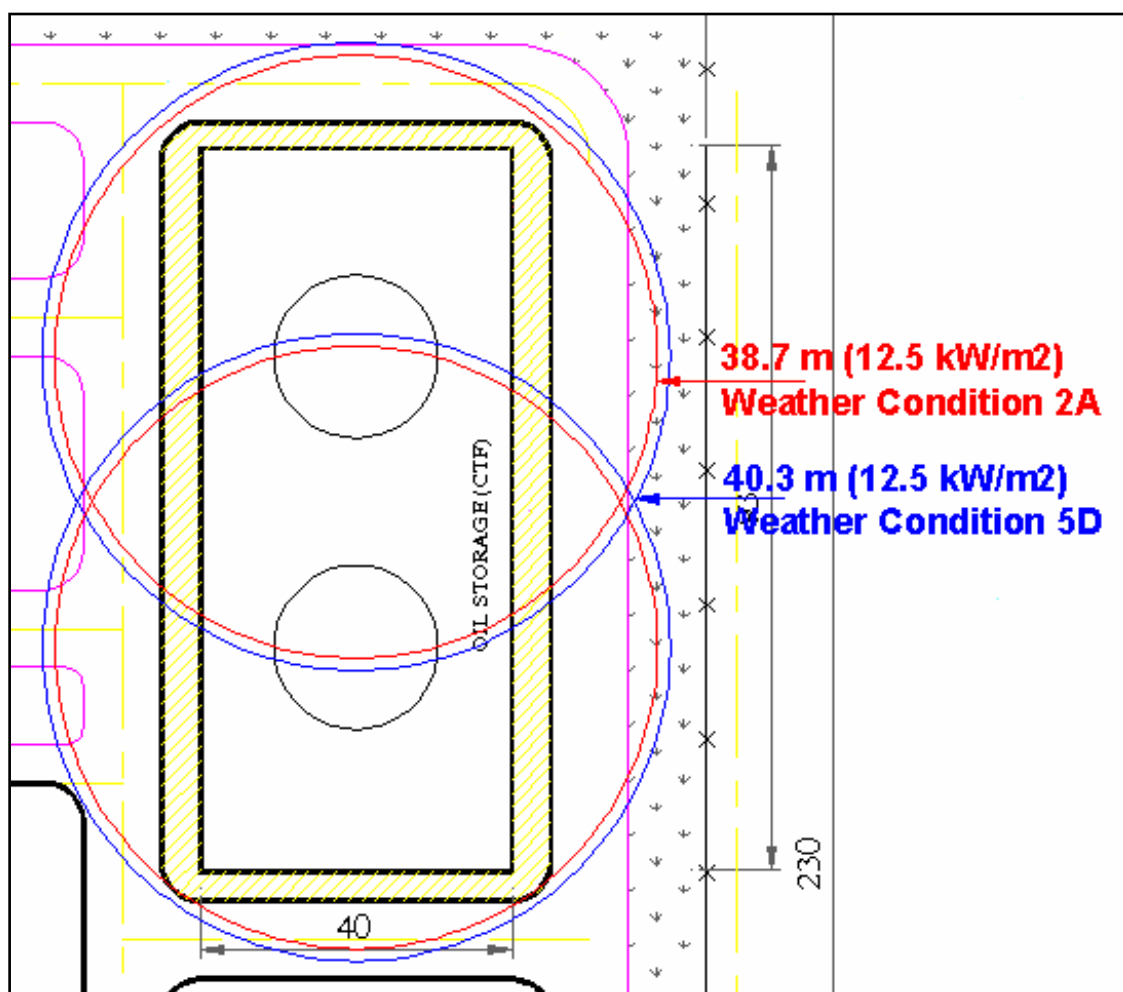


Fig. 3.9: Damage Contour for the Catastrophic Rupture of Crude Oil Storage Tank at GGS CTF Saraswati Field for the Heat Load of 12.5 kW/m²

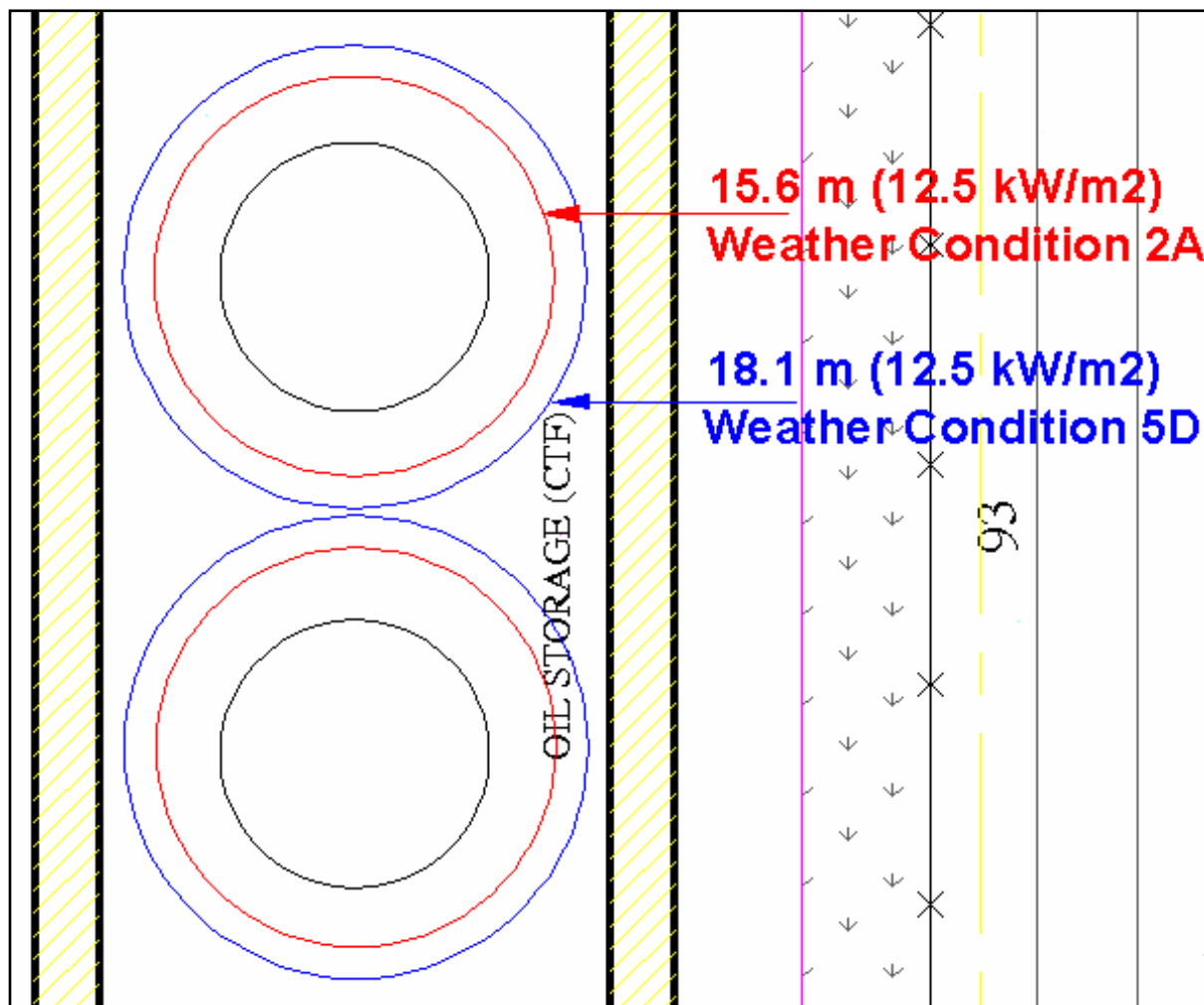


Fig. 3.10: Damage Contour for Crude Oil Storage Tank on Fire at GGS CTF Saraswati Field for the Heat Load of 12.5 kW/m^2

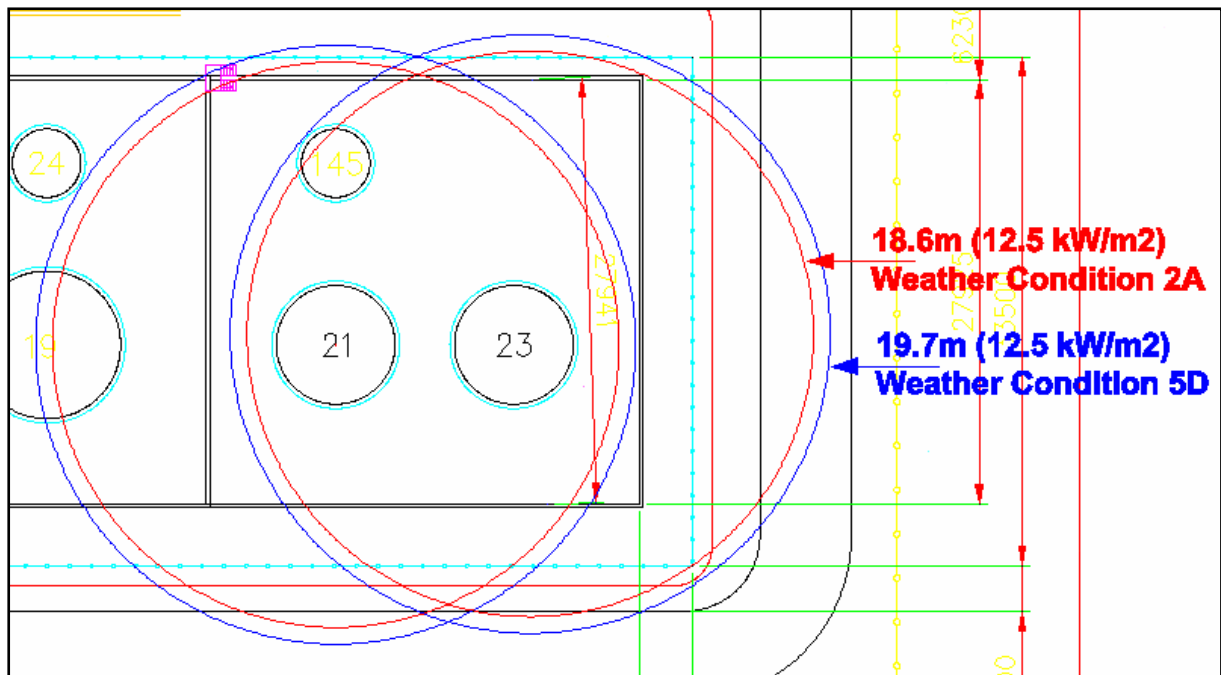


Fig. 3.11: Damage Contour for the Catastrophic Rupture of Crude Oil Storage Tank at Power Plant for the Heat Load of 12.5 kW/m^2

Table 3.16

Summary of Consequence Analysis for Jet Fire Scenario

Unit Name	Pressure (psi) / Temp. (°C)	Scenario	Mass Flow Rate (kg/s)	Weather	Damage Distance (m) for various Heat loads		
					4.0 kW/m²	12.5 kW/m²	37.5 kW/m²
Aishwariya & Mangala Field							
*Well Aishwariya (oil)	290 / 70	Blow out	16	2A	82.5	-	-
				5D	95.7	-	-
*Well Mangala (oil)	290 / 70	Blow out	16	2A	82.5	-	-
				5D	95.7	-	-
*Well Aishwariya & Mangala (gas)	1600/70	Blow out	14	2A	45.7	-	-
				5D	44.1	-	-
Leakage in upstream of choke (well fluid)	160/66	5 mm	0.45	2A	34.4	28.9	-
				5D	29.3	24.3	-
		25 mm	11.65	2A	143.4	120.4	-
				5D	122.8	100.7	-
Leakage in downstream of choke (well fluid)	130 / 47	5 mm	0.4	2A	33.4	27.9	-
				5D	28.3	23.5	-
		25 mm	10.62	2A	138.9	116.4	-
				5D	119.0	97.5	79.5
Leakage in downstream of oil heater (well fluid)	120 / 80	5 mm	0.38	2A	32.6	27.2	-
				5D	27.6	22.9	-
		25 mm	9.99	2A	135.5	113.4	-
				5D	116.0	95.0	77.6
Leakage in HP Separator Gas outlet	67 / 80	5 mm	0.017	2A	2.5	-	-
				5D	1.9	-	-
		25 mm	0.46	2A	15.6	13.5	-
				5D	13.3	11.1	9.6
Leakage in outlet of LP compressor unit (gas)	140 / 55	5 mm	0.036	2A	4.0	-	-
				5D	3.3	-	-
		25 mm	0.93	2A	21.6	18.7	16.1
				5D	18.4	15.5	13.4
Leakage in HP Separator Oil outlet	5 / 80	5 mm	0.079	2A	16.1	-	-
				5D	14.1	11.6	-
		25 mm	2.03	2A	56.9	45.7	-
				5D	50.8	42.5	-
Leakage in LP Separator Oil outlet	4 / 79	5 mm	0.07	2A	15.2	-	-
				5D	13.4	11.0	-
		25 mm	1.82	2A	54.2	43.7	-
				5D	47.6	39.8	-

Contd. Table 3.16

Unit Name	Pressure (psi) / Temp. (°C)	Scenario	Mass Flow Rate (kg/s)	Weather	Damage Distance (m) for various Heat loads		
					4.0 kW/m ²	12.5 kW/m ²	37.5 kW/m ²
Leakage in LP Separator Gas outlet	4 / 80	5 mm	0.0026	2A	-	-	-
				5D	-	-	-
		25 mm	0.069	2A	7.5	6.1	-
				5D	6.3	4.6	-
Leakage in Gas well flow line	400 / 55	5 mm	0.09	2A	7.5	5.9	-
				5D	6.2	4.5	-
		25 mm	2.57	2A	34.2	29.6	25.4
				5D	29.2	24.5	21.3
Leakage in Gas lift compressor outlet	800 / 55	5 mm	0.2	2A	10.6	9.0	-
				5D	8.9	7.3	6.3
		25 mm	5.25	2A	47.4	40.7	35.8
				5D	40.2	33.8	29.5
*Leakage in pipeline of stabilized oil from GGS	5 / 70	5 mm	0.079	2A	-	-	-
				5D	8.0	-	-
		25 mm	2.05	2A	23.2	2.1	-
				5D	33.8	6.2	-
		Rupture of pipeline	187	2A	145.8	38.6	14.8
				5D	211.9	107.2	16.8
Booster Pump failure	64 / 110	5 mm	0.27	2A	28.7	22.9	-
				5D	24.4	20.1	-
		25 mm	6.92	2A	117.9	97.5	-
				5D	100.5	82.5	-
Leakages in outlet of furnace of oil upgradation unit (GGS & CTF)	217 / 415	5 mm	0.39	2A	22.4	18.4	15.5
				5D	19.6	15.5	12.9
		25 mm	9.77	2A	93.9	76.8	65.5
				5D	82.9	65.6	54.2
Rageshwari Gas Field							
*Well (gas)	4000/105	Blow out	26	2A	58.5	-	-
				5D	47.3	-	-
Leakage in upstream of choke (well fluid)	350/42	5 mm	0.67	2A	39.6	33.7	-
				5D	33.9	28.0	-
		25 mm	16.94	2A	163.0	138.2	-
				5D	140.1	115.3	94.6
Leakage in downstream of choke (well fluid)	300/41	5 mm	0.62	2A	38.6	32.8	-
				5D	32.9	27.3	-
		25 mm	15.69	2A	158.8	134.4	-
				5D	136.6	112.2	90.3

Contd. Table 3.16

Unit Name	Pressure (psi) / Temp. (°C)	Scenario	Mass Flow Rate (kg/s)	Weather	Damage Distance (m) for various Heat loads		
					4.0 kW/m ²	12.5 kW/m ²	37.5 kW/m ²
Leakage in inlet separator (well fluid)	250/amb.	5 mm	0.57	2A	37.5	31.8	-
				5D	31.9	26.4	-
		25 mm	14.37	2A	154.2	130.2	-
				5D	132.3	108.9	87.7
Leakage in inlet pipeline to compressor (gas)	215/amb.	5 mm	0.045	2A	5.6	4.1	-
				5D	4.7	3.2	-
		25 mm	1.14	2A	26.2	22.2	19.5
				5D	22.5	18.5	19.6
Leakage in outlet pipeline from compressor to manifold (gas)	500/55.	5 mm	0.1	2A	8.4	6.9	-
				5D	7.2	5.7	-
		25 mm	2.51	2A	37.6	31.8	28.5
				5D	32.4	26.6	23.1
Leakage in pipeline to metering package (gas)	495/55.	5 mm	0.099	2A	8.4	6.9	-
				5D	7.2	5.6	-
		25 mm	2.49	2A	37.4	31.6	28.0
				5D	32.2	26.5	22.9
Leakage in pipeline to CPP (gas)	480/55	5 mm	0.096	2A	8.3	6.7	-
				5D	7.0	5.5	-
		25 mm	2.41	2A	36.8	31.2	27.6
				5D	31.7	26.1	22.7
* Gas Pipeline	480/55	5 mm	0.09	2A	-	-	-
				5D	2.8	-	-
		25 mm	2.41	2A	11.6	-	-
				5D	16.6	-	-
		Full bore rupture (12")	318.08	2A	142.6	-	-
				5D	165.4	69.3	-
Power Plant (Gas)							
* Gas Pipeline	480/55	5 mm	0.09	2A	-	-	-
				5D	2.8	-	-
		25 mm	2.41	2A	11.6	-	-
				5D	16.6	-	-
		Full bore rupture (12")	318.08	2A	142.6	-	-
				5D	165.4	69.3	-

Contd. Table 3.16

Unit Name	Pressure (psi) / Temp. (°C)	Scenario	Mass Flow Rate (kg/s)	Weather	Damage Distance (m) for various Heat loads		
					4.0 kW/m ²	12.5 kW/m ²	37.5 kW/m ²
Leakage in inlet pipeline to compressor (gas)	480/55.	5 mm	0.09	2A	-	-	-
				5D	2.8	-	-
		25 mm	2.41	2A	11.6	-	-
				5D	16.6	-	-
Leakage in outlet pipeline from compressor (gas)	600/65.	5 mm	0.2	2A	10.3	6.4	-
				5D	8.6	6.1	-
		25 mm	3.82	2A	49.3	34.6	29.0
				5D	46.1	30.9	24.5
Power Plant (Crude)							
Booster Pump failure	64 / 110	5 mm	0.27	2A	28.7	22.9	-
				5D	24.4	20.1	-
		25 mm	6.92	2A	117.9	97.5	-
				5D	100.5	82.5	-
Saraswati & Rageshwari Fields							
*Well (oil)	290/80	Blow out	6	2A	52.0	-	-
				5D	73.6	-	-
Leakage in upstream of choke (well fluid)	150/47	5 mm	0.44	2A	34.2	28.8	-
				5D	29.1	24.1	-
		25 mm	11.41	2A	142.6	119.6	-
				5D	122.2	100.1	81.4
Leakage in downstream of choke (well fluid)	100/47	5 mm	0.36	2A	31.9	26.4	-
				5D	27.0	22.4	-
		25 mm	9.31	2A	132.4	110.5	-
				5D	113.3	92.8	-
Leakage in downstream of oil heater (well fluid)	75/80	5 mm	0.3	2A	29.9	24.5	-
				5D	25.4	21.0	-
		25 mm	7.9	2A	124.3	103.2	-
				5D	106.0	87.0	-
Leakage in pipeline from HP separator outlet to flare (gas)	70/80	5 mm	0.018	2A	2.5	-	-
				5D	2.0	-	-
		25 mm	0.48	2A	15.9	13.7	-
				5D	13.5	11.3	9.6

Contd. Table 3.16

Unit Name	Pressure (psi) / Temp. (°C)	Scenario	Mass Flow Rate (kg/s)	Weather	Damage Distance (m) for various Heat loads		
					4.0 kW/m ²	12.5 kW/m ²	37.5 kW/m ²
Leakage In pipeline from HP separator outlet as a fuel (gas)	70/55	5 mm	0.012	2A	2.4	-	-
				5D	2.0	-	-
		25 mm	0.32	2A	14.7	12.5	10.9
				5D	12.6	10.4	8.8
Leakage in pipeline from LP separator outlet to flare (gas)	4/70	5 mm	0.002	2A	-	-	-
				5D	-	-	-
		25 mm	0.05	2A	7.12	5.3	-
				5D	6.2	4.2	-
Leakage in pipeline from LP separator outlet (oil)	4/65	5 mm	0.07	2A	13.5	-	-
				5D	11.9	9.8	-
		25 mm	1.78	2A	45.8	-	-
				5D	40.9	34.4	-
Leakage in pipeline to GGS (oil)	100/80	5 mm	0.35	2A	31.5	26.2	-
				5D	26.7	22.1	-
		25 mm	8.84	2A	129.2	107.7	-
				5D	110.5	90.6	-
Leakage in pipeline to 3 phase separator at GGS (oil)	40/80	5 mm	0.22	2A	26.6	-	-
				5D	22.6	18.6	-
		25 mm	5.59	2A	107.0	87.1	-
				5D	92.5	76.0	-
Leakage in pipeline to desalter train at GGS (oil)	30/80	5 mm	0.19	2A	25.2	-	-
				5D	21.3	17.6	-
		25 mm	4.84	2A	95.2	77.4	-
				5D	84.0	69.0	-
Leakage in pipeline to common CTF(oil)	60/80	5 mm	0.27	2A	28.7	22.9	-
				5D	24.3	20.1	-
		25 mm	6.84	2A	117.4	97.1	-
				5D	100.3	82.2	-

* A vertical jet is considered in case of underground pipelines and well blow out

Table 3.17
Summary of Consequence Analysis for Pool Fire Scenario

Unit Name	Pressure (psi) / Temp. (°C)	Scenario	Mass Flow Rate (kg/s)	Pool radius (m)	Weather	Damage Distance (m) for various Heat loads		
						4.0 kW/m ²	12.5 kW/m ²	37.5 kW/m ²
Aishwariya and Mangala Field								
Leakage in upstream of choke (well fluid)	160 / 66	5 mm	0.45	0.7	2A	20.8	19.2	17.9
				0.7	5D	20.8	19.2	17.9
		25 mm	11.65	12.7	2A	70.8	45.5	-
				11.3	5D	80.1	52.4	-
Leakage in downstream of choke (well fluid)	130 / 47	5 mm	0.4	1.1	2A	21.4	18.8	16.8
				1.1	5D	21.4	18.8	16.8
		25 mm	10.62	12.7	2A	67.4	41.9	-
				12.0	5D	75.7	46.5	-
Leakage in downstream of oil heater (well fluid)	120 / 80	5 mm	0.38	0.82	2A	21.6	19.8	18.4
				0.82	5D	21.6	19.8	18.4
		25 mm	9.99	11.25	2A	68.1	44.5	-
				9.93	5D	76.6	52.1	-
Leakage in HP Separator Oil outlet	5 / 80	5 mm	0.079	1.2	2A	10.5	7.6	5.4
				1.2	5D	10.7	8.5	6.8
		25 mm	2.03	6.6	2A	34.8	19.1	10.5
				6.5	5D	37.3	23.4	10.9
Leakage in LP Separator Oil outlet	4 / 79	5 mm	0.07	1.17	2A	10.1	7.4	5.2
				1.15	5D	10.3	8.2	6.6
		25 mm	1.82	6.2	2A	33.6	18.6	9.9
				6.1	5D	35.9	22.9	10.4
*Leakage in pipeline of stabilized oil from GGS	5 / 70	5 mm	0.079	1.14	2A	12.3	9.7	7.6
				1.13	5D	14.1	12.1	10.5
		25 mm	2.05	6.06	2A	33.8	19.2	10.3
				5.76	5D	40.1	28.1	15.7
		Rupture of oil pipeline	187	65.4	2A	139.2	79.9	-
				61.9	5D	157.6	74.9	-
Leakage in oil buffer tank (12.5m ID x 9.5m Ht)	Ambient	5 mm	0.1	1.58	2A	13.5	9.8	6.6
				1.57	5D	13.9	10.9	8.4
		25 mm	2.79	8.3	2A	39.5	19.9	-
				8.2	5D	43.3	23.9	-

Contd. Table 3.17

Unit Name	Pressure (psi) / Temp. (°C)	Scenario	Mass Flow Rate (kg/s)	Pool radius (m)	Weather	Damage Distance (m) for various Heat loads		
						4.0 kW/m ²	12.5 kW/m ²	37.5 kW/m ²
Rupture of oil buffer tank (12.5m ID x 9.5m Ht) (dyke = 648 m)	Ambient	1170 m ³		14.3	2A	43.9	17.3	-
				14.3	5D	52.4	19.1	-
Oil buffer tank on fire (12.5m ID x 9.5m Ht)	Ambient	1170 m ³		12.5 dia.	2A	30.4	15.4	-
					5D	32.6	19.4	-
Booster Pump failure	64/110	5 mm	0.27	0.7	2A	17.5	15.8	14.8
				0.7	5D	17.5	15.8	14.8
		25 mm	6.92	8.6	2A	54.9	34.7	-
				7.5	5D	58.0	40.9	29.1
Leakage in oil storage tank at CTF (46m ID x 11.5m Ht)	Ambient	5 mm	0.11	1.66	2A	14.1	10.1	6.7
				1.64	5D	14.4	11.3	8.6
		25 mm	3.08	8.76	2A	40.7	20.4	-
				8.68	5D	44.8	24.1	-
Rupture of oil storage tank at CTF (46m ID x 11.5m Ht) Dyke=75m x 210m)	Ambient	18710 m ³	-	70.8	2A	147.7	77.7	-
				70.8	5D	171.2	80.1	-
Rupture of 2 oil storage tank at CTF (46m ID x 11.5m Ht) (Dyke=75m x 210m)	Ambient	37420 m ³	-	70.8	2A	147.7	77.7	-
				70.8	5D	171.2	80.1	-
Oil storage tank at CTF on fire (46m IDx11.5m Ht)	Ambient	18710 m ³	-	46 dia.	2A	58.9	25.9	-
					5D	69.9	27.1	-
Leakage in diluent storage tank at CTF	Ambient	5 mm	0.12	1.77	2A	18.6	12.7	7.4
				1.77	5D	19.1	14.4	9.6
		25 mm	3.1	8.88	2A	40.1	22.2	13.8
				8.88	5D	42.9	26.6	13.8
Rupture of diluent storage tank at CTF	Ambient	40,000 T	-	70.8	2A	140.3	77.0	-
				70.8	5D	157.4	79.5	-
Rageshwari Gas Field								
Leakage in upstream of choke (well fluid)	350/42	5 mm	0.67	0.61	2A	27.7	26.4	25.5
				0.61	5D	27.7	26.4	25.5
		25 mm	16.94	9.19	2A	78.6	57.6	-
				7.75	5D	83.1	65.3	53.3

Contd. Table 3.17

Unit Name	Pressure (psi) / Temp. (°C)	Scenario	Mass Flow Rate (kg/s)	Pool radius (m)	Weather	Damage Distance (m) for various Heat loads		
						4.0 kW/m ²	12.5 kW/m ²	37.5 kW/m ²
Leakage in downstream of choke (well fluid)	300/41	5 mm	0.62	0.59	2A	22.2	20.9	20.0
				0.59	5D	22.2	20.9	20.0
		25 mm	15.69	9.37	2A	74.4	53.2	-
				8.09	5D	84.0	65.2	-
Leakage in inlet separator (well fluid)	250/amb	5 mm	0.57	0.64	2A	23.6	22.2	21.2
				0.64	5D	23.6	22.2	21.2
		25 mm	14.37	14.1	2A	76.2	49.6	-
				12.6	5D	83.6	53.2	-
Power Plant (Crude)								
Booster Pump failure	64/110	5 mm	0.27	0.7	2A	17.5	15.8	14.8
				0.7	5D	17.5	15.8	14.8
		25 mm	6.92	8.6	2A	54.9	34.7	-
				7.5	5D	58.0	40.9	29.1
Leakage in crude oil day tank	Ambient	5 mm	0.11	1.62	2A	13.8	10.0	6.7
				1.61	5D	14.2	11.1	8.5
		25 mm	2.84	8.42	2A	39.7	20.1	-
				8.34	5D	43.8	24.2	-
Rupture of crude oil day tank	Ambient	400m ³	-	15.7	2A	46.2	18.6	-
				15.7	5D	54.9	19.7	-
Saraswati & Rageshwari Fields								
Leakage in upstream of choke (well fluid)	150/47	5 mm	0.44	1.0	2A	22.5	20.3	18.5
				1.0	5D	22.5	20.3	18.5
		25 mm	11.41	2.25	2A	41.5	36.1	31.1
				2.08	5D	44.3	40.4	36.5
Leakage in downstream of choke (well fluid)	100/47	5 mm	0.36	1.27	2A	19.9	16.9	14.4
				1.27	5D	26.4	25.5	24.9
		25 mm	9.31	4.23	2A	44.3	36.9	25.3
				3.88	5D	46.5	38.8	28.8
Leakage in downstream of oil heater (well fluid)	75/80	5 mm	0.3	0.99	2A	18.4	16.2	14.5
				0.99	5D	29.2	28.5	28.2
		25 mm	7.9	3.94	2A	40.7	37.1	22.4
				3.69	5D	42.2	34.5	25.5
Leakage in pipeline from LP separator outlet (oil)	4/65	5 mm	0.07	1.22	2A	10.4	7.6	5.4
				1.20	5D	10.7	8.5	6.8
		25 mm	1.78	6.39	2A	34.1	18.7	10.1
				6.31	5D	36.4	22.9	10.4

Contd. Table 3.17

Unit Name	Pressure (psi) / Temp. (°C)	Scenario	Mass Flow Rate (kg/s)	Pool radius (m)	Weather	Damage Distance (m) for various Heat loads		
						4.0 kW/m ²	12.5 kW/m ²	37.5 kW/m ²
Leakage in pipeline to GGS (oil)	100/80	5 mm	0.35	0.86	2A	19.6	17.6	16.2
				0.86	5D	19.6	17.6	16.2
		25 mm	8.84	10.5	2A	62.2	34.4	-
				9.5	5D	67.6	44.3	-
Leakage in pipeline to 3 phase separator at GGS (oil)	40/80	5 mm	0.22	1.65	2A	16.6	12.2	9.8
				1.40	5D	17.6	15.0	12.2
		25 mm	5.59	10.02	2A	48.4	26.1	-
				9.65	5D	54.7	34.5	-
Leakage in pipeline to desalter train at GGS (oil)	30/80	5 mm	0.19	1.72	2A	16.0	11.9	8.5
				1.65	5D	16.8	13.6	10.9
		25 mm	4.84	9.6	2A	45.7	24.2	-
				9.4	5D	50.5	27.2	-
Leakage in pipeline to common CTF(oil)	60/80	5 mm	0.27	1.2	2A	17.8	15.1	12.8
				1.2	5D	22.0	21.0	20.4
		25 mm	6.84	10.46	2A	54.5	31.8	-
				9.88	5D	59.9	35.6	-
Leakage in oil buffer tank (5m ID x 3.5m Ht)	Ambient	5 mm	0.072	1.31	2A	11.0	7.9	5.4
				1.29	5D	11.7	9.2	7.4
		25 mm	1.86	6.85	2A	35.2	18.7	10.4
				6.79	5D	37.9	23.0	10.6
Rupture of oil buffer tank (5m ID x 3.5m Ht) (dyke 875m)	Ambient	65.5 m ³	-	16.6	2A	47.5	24.4	-
				16.6	5D	38.5	27.3	-
Oil buffer tank on fire (5m ID x 3.5m Ht)	Ambient	65.5 m ³	-	5 dia	2A	15.9	9.9	-
					5D	15.7	10.9	-
Leakage in oil storage tank at CTF (21m ID x 11m Ht)	Ambient	5 mm	0.11	1.62	2A	13.8	10.0	6.7
				1.61	5D	14.2	11.1	8.5
		25 mm	2.94	8.56	2A	40.1	20.2	-
				8.48	5D	44.2	23.9	-
Rupture of oil storage tank at CTF (21m Id x 11m Ht) (dyke = 50mx70m)	Ambient	3750 m ³		34.5	2A	81.5	38.7	-
				34.5	5D	96.6	40.3	-
Rupture of 2 oil storage tank at CTF (21m ID x 11m Ht)	Ambient	7500 m ³		34.5	2A	81.5	38.7	-
				34.5	5D	96.6	40.3	-

Contd. Table 3.17

Unit Name	Pressure (psi) / Temp. (°C)	Scenario	Mass Flow Rate (kg/s)	Pool radius (m)	Weather	Damage Distance (m) for various Heat loads		
						4.0 kW/m ²	12.5 kW/m ²	37.5 kW/m ²
Oil storage tank at CTF on fire (21m ID x 11m Ht)	Ambient	3750 m ³		21 dia,	2A	38.3	15.6	-
					5D	44.0	18.1	-
Oil Tanker	Ambient	20kL	50.2	22.86	2A	123.8	90.9	-
				20.35	5D	137.3	97.3	-
Oil Tanker	Ambient	12kL	20.8	14.04	2A	89.8	63.4	-
				11.32	5D	101.8	74.0	-

3.11 Failure Frequency Analysis

3.11.1 Blowout Modelling

A **blowout** is defined as an uncontrolled release of fluid from a well. It is most hazardous when the fluid is hydrocarbon (oil and/or gas), but drilling mud, completion fluid or water may also be blown out. Blowouts are important because they have the potential to release large amounts of hydrocarbons and are very difficult to control.

A **well control incident** (or well problem) covers a range of events that have the potential to result in blowouts, but where a release either does not occur or is quickly stopped. They typically involve formation fluid accidentally entering the wellbore, but controlled by the available barriers such as the blowout preventer (BOP). These incidents usually have relatively minor consequences, and are not well reported.

For some events, it is unclear whether they should be counted as a full blowout or as a well control incident. Different databases categorise events in different ways, and some analyses use the term "blowout" to refer to all well control incidents.

3.11.2 Data Sources

The main compilations of data on blowouts are:

SINTEF blowout database - an internal SINTEF compilation sponsored by 6 operators and 2 consultants (Holand 1995). It includes 319 blowouts for the period 1970-94, of which 128 occurred in the US GoM OCS or North Sea during 1980-94, the period for which coverage is believed complete and for which there are related well populations. It is an update of the Marintek blowout database, for which the full list (SINTEF 1983) and an analysis (NSFI 1985) were published. Detailed analyses have been published for the period

1980-93 (Holand 1996, 1997). Scandpower (1995) analysed the data for the period 1980-92, and included a full list of the events.

E&P Forum database - Frequencies from BLOWOUT for the period 1970-85 were published by OCB / Technica (1988) and E&P Forum (1992).

WOAD – World Offshore Accident databank, a public-domain database. It includes 312 blowouts world-wide from 1970-96 of which 135 occurred in the US GoM or North Sea during 1980-96. It also has well populations for the US GoM OCS and North Sea. WOAD has been updated to include data from the SINTEF and BLOWOUT databases, but no detailed analyses are available yet.

The differences between the available analyses of these databases is discussed further with reference to blowout frequency.

3.12 Causes of Blowouts

3.12.1 Causes of Drilling Blowouts

Well control can be lost as a result of:

- ◆ Formation fluid entry into the wellbore.
- ◆ Loss of containment due to maloperation (e.g. during wirelining).
- ◆ Wellhead damage (e.g. by fires, storms, dropped objects, etc).

In drilling, the most common cause of lost control is an unexpected entry of formation fluid. Possible reasons are:

Shallow Gas

In shallow unconsolidated formations (typically in the top 500m) there may be pockets of shallow gas, which has migrated up from lower formations and is trapped below layers of clay. In these regions, through which the conductor is usually driven, no BOP is used, and there may be no mud in the hole. Since the hole is also shallow, if it strikes a shallow gas pocket, the gas may very rapidly emerge at the rig. Operators take precautions by conducting shallow seismic surveys, which should provide warning if the hazard exists. Nevertheless, shallow gas remains one of the main causes of blowouts.

High Formation Pressure

Drilling into an unexpected zone of high pressure may allow formation fluids to enter the well before the mud weight can be increased to prevent it.

Insufficient Mud Weight

Drilling mud is the primary barrier against fluid influx. Mud weights are chosen to maintain a balance between high drilling rate (which requires a low mud weight) and safety against influx of formation fluids (which requires a high mud weight). This small margin of safety may be lost if the mud weight is incorrectly set. This most commonly occurs as a result of drilling through a high pressure gradient.

Lost Circulation

If the well is drilled into a highly permeable or fractured formation, the mud may flow into the formation instead of returning up the annulus to the rig. This reduces the hydrostatic pressure in the annulus, and may allow fluid from another formation to enter the wellbore.

Gas-cut Mud

If the formation is highly productive, fluid may mix with the mud, reducing its density and lowering the pressure on the formation. If the fluid is gas, it expands as it is circulated up, and emerges on the rig. Oil-based mud is particularly vulnerable to this hazard.

Swabbing

When the drill pipe is pulled out of the hole, suction is created in the hole beneath the bit. If the drill pipe is removed too quickly and mud is not pumped in sufficiently to compensate for the removed pipe, the reduced pressure may allow formation fluid to enter.

Analysis of the causes of blowouts is complicated by the fact that many blowouts are caused by a combination of several problems, and details are often unavailable. The SINTEF database gives the best available information on blowout causes. A detailed analysis of the causes in each phase of operation (exploration, development, workover etc. is given by Holand (1996, 1997). An overall summary is given by Holand (1995).

The underlying causes of most of these events can be interpreted as organisational or managerial. An analysis of blowout causes into such factors was attempted for the Marintek database (NSFI 1985). The results showed that the main factors were improper maintenance, lack of attention to operations, and inadequate supervision.

3.12.2 Causes of Production Blowouts

Blowouts during production are commonly caused by well interventions such as workovers, wirelining, snubbing and coiled tubing operations, although some production blowouts are initiated by the well equipment in normal operation.

3.12.3 Blowouts due to External Causes

Possible external causes of blowouts include:

- ◆ Escalation from process fire
- ◆ Structural collapse
- ◆ Military or pirate attacks

These should not be included in the analysis of blowouts if they are separately modelled under the other hazard categories. However, for simple studies that do not model such escalations in full, it is appropriate to include them as blowouts.

The analysis of the SINTEF database excludes external causes, whereas the analyses of the WOAD and BLOWOUT databases include them.

3.12.4 Blowout Frequencies

Data Selection

Blowout frequency estimates are obtained from a combination of incident experience and associated exposure in a given area over a given time period. Ideally, a blowout frequency should be estimated from recent experience in the country's operations context and on the type of installation for which the risks are to be predicted. In practice, there have been so few blowouts that a large geographical area and a long time period are required to obtain statistically reliable frequencies. The problems of poor reporting of incidents in some parts of the world, or lack of previous analyses of reported data, also restrict the choice of data.

For QRAs of installations in the US Gulf of Mexico (US GoM), blowout experience in this area is suitable, since it provides a large dataset with good reporting of accidents. Usually the Outer Continental Shelf (OCS) of the US Gulf of Mexico is used, because no well population data is available for the onshore US State Waters. In many cases, North Sea experience is combined with the US GoM OCS experience for consistency with North Sea analyses.

For QRAs of installations in the North Sea, blowout experience in the North Sea is limited, and differences to the US GoM frequencies are in general not statistically significant. Blowout frequency estimates are commonly obtained from combined experience in the North Sea and US GoM. This area has broadly uniform drilling procedures, and gives a larger dataset that is reasonably well reported.

Most other countries do not have sufficient experience to give blowout frequencies significantly different to the North Sea/US average.

Severity of Events

The severity of the events included in the analysis has an influence on the resulting frequency. It is desirable to distinguish between full blowouts and more minor well control incidents, but the distinction is not always clear. Full blowouts are of the greatest concern, but may be too infrequent to give reliable frequencies. Well control incidents are more frequent, but are less well reported.

Measures of Exposure

The measure of exposure determines the units of the resulting frequency. Which measure of exposure is appropriate depends on the requirements of the study. Blowout frequencies may be expressed in various forms:

- ◆ Blowout frequencies **per installation year** are useful for simple studies, where it is not necessary to take the number and type of wells into account, or the level of drilling activity on the platform. This measure is useful for drilling rigs, where drilling activities are in progress for most of the time
- ◆ Blowout frequencies **per well drilled** are relevant to blowouts during drilling and completion. This measure is useful for integrated installation where the amount of drilling varies through the installation's life
- ◆ Blowout frequencies **per well year** are relevant for blowouts during normal production
- ◆ Blowout frequencies **per well operation** are relevant to blowouts during workover and wirelining. This measure is useful when it is necessary to take into account the level of workover and wirelining activity. Alternatively, the frequency may be included in the production blowout frequency per well year, using an average rate of workovers or wirelining per well year

All these approaches are to be used where appropriate.

The annual blowout frequency for the installation is obtained by multiplying the blowout frequencies per operation or per well year by the number of wells drilled, completed, in operation or being worked over each year. For a drill rig, this is a constant at a given level

of activity. For a production installation, the blowout frequency is usually highest during the drilling years early in its life.

3.12.5 Blowout Frequencies Based on Phase of Operation

Blowout frequencies are often expressed in terms of the type of operations on the installation. The following phases of operation are distinguished:

- ◆ Exploration drilling (wildcat + appraisal wells)
- ◆ Development drilling
- ◆ Completion
- ◆ Production
- ◆ Workover
- ◆ Wirelining (sometimes included in production)

The different phases are exposed to different hazards and will have different safety measures in place. This split allows the analysis to take account of these features, and also to reflect the level of drilling, workover and wirelining activity and the number of wells in production.

The analysis of the SINTEF database for the US GoM OCS/North Sea for the period 1980-92 by Scandpower (1995) gave the blowout frequencies shown in **Table 3.18**. These are also presented by E&P Forum (1996). The analysis gives trend information but concludes that these are not statistically significant.

Table 3.18

Blowout Frequencies by Phase of Operation (Scandpower 1995)

Phase	Blowouts 1980-92	Exposure 1980-92	Blowout Frequency
Exploration drilling	43	5781 wells	7.5×10^{-3} per well drilled
Development drilling	33	9513 wells	3.5×10^{-3} per well drilled
Completion	7	7041 wells	1.0×10^{-3} per well completed
Production	6	112,720 well years	5.3×10^{-5} per well year
Workover	19	23,200 workovers	8.1×10^{-4} per workover
Wirelining	4	193,700 wireline jobs	2.1×10^{-5} per wireline job

The results show that exploration drilling is much more hazardous than development drilling.

3.12.6 Blowout Frequencies Based on Fluid Released

Blowouts may be categorised according to the source of the release:

- ◆ Deep blowouts occur from the intended target reservoir for the well
- ◆ Shallow gas blowouts occur from unexpected pockets of gas much closer to the sea bed. These are typically depths less than 1200m, while the well is contained only by conductor casing without a BOP. In such cases, a diverter is usually used

The overall proportion of incidents in drilling which involve shallow gas is approximately 60%. There is no significant difference in the proportion between exploration and development drilling (although the actual frequency is greater in exploration drilling).

Table 3.19 gives deep and shallow gas blowout frequencies from the analysis by Scandpower (1995) of the SINTEF database. These are also presented by E&P Forum (1996).

For production wells, separate frequencies can be calculated for oil and gas wells, although the reduced numbers of events in each category gives less statistical confidence in the results. Results of this type from the SINTEF database for 1980-96 are given in **Table 3.20**. This shows that gas wells have higher blowout frequencies than oil wells.

Table 3.19

Drilling Blowout Frequencies by Fluid Released (Scandpower 1995)

Phase	Fluid Type	Blowout Frequency (per well drilled)
Exploration drilling	Shallow gas	4.7×10^{-3}
	Deep	2.8×10^{-3}
	Total	7.5×10^{-3}
Development drilling	Shallow gas	2.0×10^{-3}
	Deep	1.5×10^{-3}
	Total	3.5×10^{-3}

Table 3.20

Blowout Frequencies By Fluid In Well

Phase	Fluid	Blowout Frequency
Production	Gas	9.8×10^{-5} per well year
	Oil	5.7×10^{-5} per well year
	Total	7.5×10^{-5} per well year
Workover	Gas	1.8×10^{-3} per workover
	Oil	4.6×10^{-4} per workover
	Total	1.1×10^{-3} per workover
Wirelining	Gas	4.8×10^{-5} per wireline job
	Oil	1.1×10^{-5} per wireline job
	Total	3.2×10^{-5} per wireline job

3.12.7 Blowouts in Individual Drilling Operations

Holand (1996, 1997) gives a breakdown of blowouts according to the individual operations in which they occurred. Scandpower (1995) summarised this data into the following major categories of operations:

- ◆ **Drilling**, i.e. the period when the bit is on the bottom
- ◆ **Tripping**, including time when the drill string is running into the hole (RIH), pulling out of the hole (POOH) and held out of the hole
- ◆ **Running casing**, including time when casing is being run, waiting for cement to harden, and pressure-testing the casing
- ◆ **Other**, including installing the BOP (nipple-up/nipple-down), milling, wirelining, waiting on weather etc.

These categories were further sub-divided into two phases:

- ◆ Prior to installing BOP, i.e. drilling the top hole
- ◆ After the BOP is installed

Table 3.21 shows the contributions of the individual operations to the total blowout frequency for exploration and development drilling.

Table 3.21

Contribution of Individual Operations to Blowout Frequencies (Scandpower 1995)

Operation	Exploration Drilling (%)	Development Drilling (%)
Before installing BOP		
Drilling	20.9	9.1
Tripping	14.0	24.2
Running casing	7.0	15.2
Other	20.9	9.1
After installing BOP		
Drilling	16.3	9.1
Tripping	7.0	15.2
Running casing	2.3	6.1
Other	11.6	12.1
TOTAL	100	100

The blowout frequencies for the individual operations are uncertain due to the small number of total events (51 incidents overall) and uncertainty about how representative the chosen drilling programme was of average practice. Nevertheless, a sensitivity analysis indicated that the following conclusions were valid:

- ◆ The most hazardous operations (in declining order of incident frequency per hour) were:
 - POOH from surface zone (i.e. prior to installing the BOP)
 - POOH from intermediate zone (i.e. prior to reaching the expected reservoir)
- ◆ Drilling in surface zone: Their incident frequencies were between 20 and 10 times higher than average
- ◆ The least hazardous operations were coring and logging. Their incident frequencies were between 5 and 10 times less than average
- ◆ The incident frequencies of other operations (including drilling in the pay zone) were not significantly different from average

This analysis indicated that precautionary shut-down would be most effective during the most hazardous operations as indicated above.

3.12.8 Blowouts in Individual Wells

The procedures and protective measures that are in place to prevent blowouts will obviously influence the blowout frequency. Quantification of this effect is difficult due to the complexity of blowout causes, and the lack of data on the effects of preventative measures on them. Some studies have attempted to estimate the blowout frequency for specific wells using fault tree analysis. This is necessarily based on judgement in many areas, but can give insight into the effectiveness of measures to reduce blowout frequencies. Other studies have modified generic frequencies using statistics on the causes of previous blowouts. Scandpower (1995) describe a model that is able to adjust generic blowout frequencies to reflect detailed features of design and management for an individual well. In most studies, the generic frequencies are applied to all wells without modification.

3.12.9 Blowouts on Injection Wells

There is no available data on blowout frequencies for injection wells. The following assumptions are made:

- ◆ For gas injection wells, the blowout frequencies are the same as for gas production wells
- ◆ For water injection wells, the blowout frequencies during drilling are as for any other well, and the blowout frequency during production and workover is zero

Underground Pipelines

Data Sources

There are several data sources containing varying degrees of information; some are available in their raw data form, whilst some are available only in summary.

The main sources of information are:

UK Gas Transmission Lines 1969-77 from the British Gas Corporation as published by the Health and Safety Executive in their St. Fergus to Mossmorran NGL pipeline study (HSE, 1978). This data covers some 14,228 km of pipeline and includes leak sizes and causes.

UK Cross Country Pipelines 1963-76 also from the HSE report mentioned above (HSE, 1978). Some 2,400 km of pipeline carrying diverse materials - unfortunately however there is a lack of useful detail in this data set.

CONCAWE - European Oil and Product Lines 1976-84. CONCAWE produces a detailed annual report and a running 5 year analysis of their 19,000 km of lines. However

they express failure size in terms of volume of liquid spilt rather than the dimensions of the hole, so it is difficult to relate this information to leak size.

US Gas Transmission Lines 1970-80. Information regarding these lines is collected by the US Department of Transportation Hazardous Information System from their incident report forms, and is stored in computerised form for ready access. Operators are compelled by statute to complete both the incident reporting forms and an annual return of pipeline mileage in various classes. In addition Battelle Columbus Laboratories analyse this information every year for the American Gas Association and present their results in published reports. The length of pipelines included in this database is around 400,000 km, and it is therefore the largest such database for gas pipelines, by a wide margin.

US Oil Pipeline Data 1970-80. The Department of Transportation also collects data on liquid lines in similar manner to that for the gas line system. Again, this is a very extensive network of pipelines (about 400,000 km).

A comparison of the failure rate frequencies, which may be derived from these data, is given in **Table 3.22**.

Table 3.22

Comparison of Failure Rate Frequencies (per 1000 km years)

Pipeline System Failure Mode	USA Gas-Line Data 1970-80 Raw Data (Note 1)	UK Gas 1969-77 (HSE)	HSE NGL Risk Study (Derived from CONCAWE Data)	European Oil and Gas Lines 1974-84 (CONCAWE Unmodified Data)
Defect	0.13	0.07	0.07	0.16
Corrosion	0.20	0.16	0	0.23
External Impact	0.31	0.16	0.16	0.22
Environmental	0.11	0.007	0.007	0.05
Operational / other	0.035	0.17	0	0.03
Total (Note 2)	0.79	0.56	0.23	0.69

Note 1: This total figure reduces to approximately 0.2-0.3 per 1000 km years when old and substandard pipelines are excluded.

Note 2: The total values given are based on the sum of the failure modes given to more decimal places than shown in this table. Hence there may be some discrepancy when simply adding the values shown.

The most useful source is the US gas line database. It has by far the greatest

detail, and enables great flexibility of analysis because of its availability in computerised raw form. This allows the analyst to exclude old pipelines, and those not built to a suitable design code, from the statistics.

3.13 Derivation of Overall Failure Rate

The US data is built up from reports on a large number of accidents, some of which happened on pipeline systems, which were significantly different from the pipelines investigated in this study. Therefore a number of incidents and pipelines can be eliminated from the data prior to further analysis.

The following elimination procedure has been adopted.

Eliminating certain incidents because of their inapplicability. These are:

- ◆ Those incidents, which occurred in any part of the pipeline system other than the pipeline itself
- ◆ Those incidents where the leak originated at a longitudinal weld, compressor, gas cooler or other part
- ◆ Those incidents which occurred within buildings
- ◆ Those corrosion failures which occurred on pipe which was either not cathodically protected or was bare
- ◆ Those construction defects or material failures which occurred on pipe which had not been hydrostatically tested

Eliminating certain classes of pipeline and associated incidents including:

- ◆ Pipelines classified anything other than transmission lines
- ◆ Pipelines which were not steel
- ◆ Pipelines where the year of installation was given as pre-1950 on the grounds that they would have been built to lower specifications in terms of design, materials or construction techniques than would be the case today
- ◆ Pipelines neither coated nor wrapped and not cathodically protected. It is considered that the small number of pipelines fitting this description might be sub-standard or untypical in other respects

After these cases had been eliminated the remaining incidents were processed to give a graph of failure rates versus pipeline diameter. This is illustrated in **Fig. 3.12**.

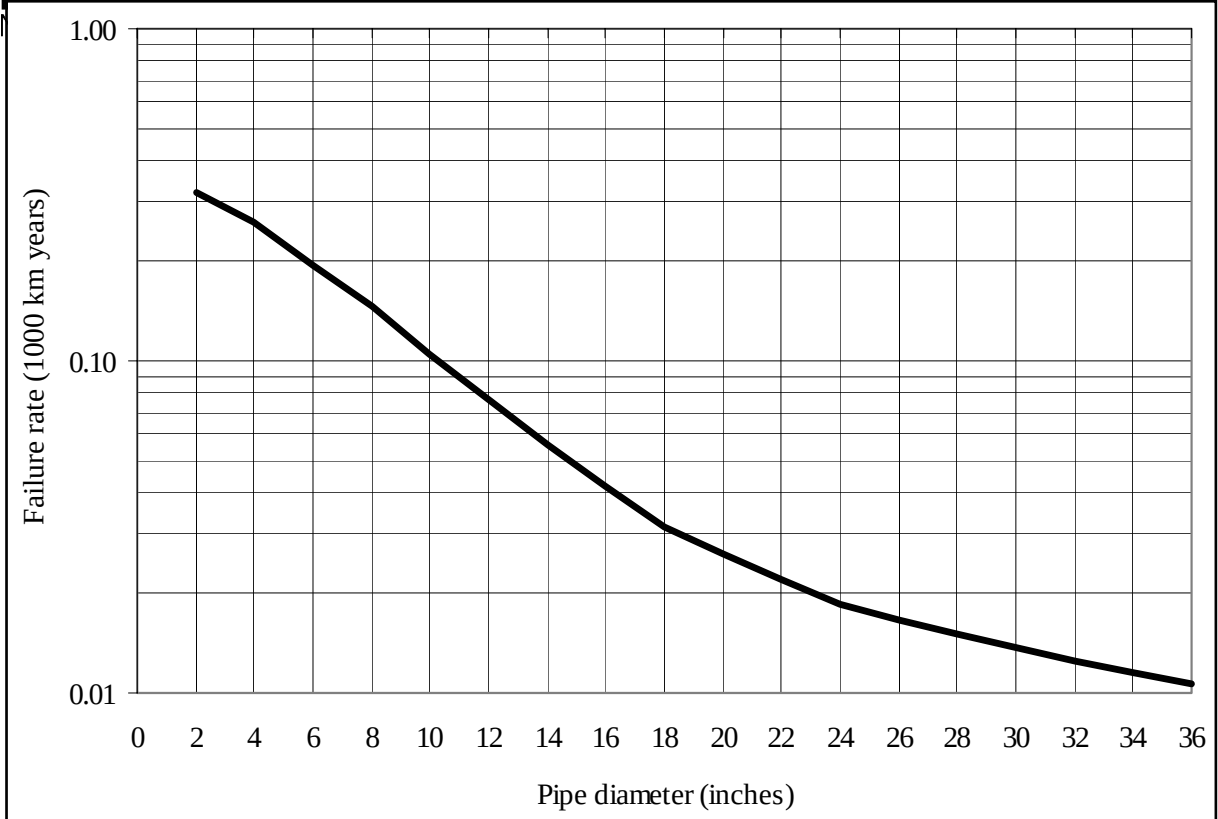


Fig. 3.12: Failure Rate as a Function of Pipe Diameter

3.14 Breakdown of Failure Rate by Leak Size

The magnitude of leaks from pipelines can be quantified in several different ways (such as amount spilled or crack length). However for the purpose of assessing possible hazards, the only useful one is that giving the size of hole in terms of equivalent diameter for flow rate calculation purposes. Unfortunately, there is only one published source of data, that for UK Gas Transmission lines, which actually presents leak magnitudes in this way: however, it appears that these quoted figures were not based on actual observed sizes but were ascribed to the data afterwards through consideration from experience of the distribution of failure modes and hole sizes associated with them.

The US Transmission data does not generally include information on leak sizes although crack lengths are recorded in the case of full bore failures.

The raw US data was therefore examined in more detail by reading each individual printout, to be in a position to make a judgement about the size of the incident. The judgement was made primarily on the basis of cost of damage, as this was the only piece of information that could be judged relevant to the leak size, when the size was not quoted.

Three main categories were chosen: small, medium and large. This *large* category would also include catastrophic ruptures, but would not exclusively consist of them. Where

the leak size was quoted, the classification of the incident was changed as appropriate. Each report was also scanned for consistency and the occurrence of major ruptures.

On looking through the corrosion incidents there appeared to be several cases of multiple reporting of the same incident (at least the same pipeline, same day and so on) so that these cases were excluded from the failure data for the breakdown by leak size. In the case of natural hazards, these were judged to produce predominantly major failures. The resulting distribution suggested is shown in **Table 3.23**. For incidents listed as due to *other causes*, some 5% were found to be major ruptures: assuming a further 5% were large releases an overall distribution by failure mode was arrived at.

Table 3.23
Classification of Incident Size by Failure Mode

Failure Mode	Size of Incident			
	Small	Medium	Large	Total
Defect	57%	24%	19%	100%
Corrosion	66%	15%	19%	100%
External Impact	71%	22%	7%	100%
Natural Hazards	10%	10%	80%	100%
Other Causes	70%	20%	10%	100%

3.14.1 Combination of Cause and Leak Size

The combination of all the factors discussed in the preceding sections with respect to overall values of pipeline failure rates, diameter dependence, hole size apportionment and so on, produces the following table of failure rates broken down by cause and failure size.

Table 3.24
Base Failure Frequencies by Failure Mode and Hole Size

Failure Mode	Failure Frequency (per 1000 km year)				
	25 mm	50 mm	100 mm	Full bore	Total
Defect	0.0115	0.0031	0.0014	0.0046	0.021
Corrosion	0.0052	0.0022	0.0010	0.0033	0.012
External Impact	0.0022	0.0003	0.0001	0.0004	0.003
Natural Hazards	0.0015	0.0045	0.0015	0.0060	0.014
Other Causes	0.0028	0.0005	0.0002	0.0007	0.004
Total	0.0231	0.0106	0.0043	0.0149	0.053

It can be seen that the final failure frequencies derived are significantly lower than the *raw* failure rates from several databases. This is because of the exclusion process and also the major reduction of external impact frequency for the pipeline diameter.

These data are applied to both oil and gas lines. Although these lines are different, the raw data show similar frequencies between CONCAWE oil and gas line data and US gas line data. The frequencies used for oil lines would be on the slightly conservative side, but this is reasonable for the present study.

Overground Piping

For welded piping, general pipe leak frequency data are as shown in **Table 3.25**. This is considered to be the best data on pipe failures, which has been identified, and hence is the basis for the data used in this study.

Table 3.25
Historical Pipe Leak Frequencies

Type	% of Cross-Sectional Area	Frequency (per year)
Small Leaks	<1	2.8×10^{-7}
Big Leaks	5	1.2×10^{-7}
Catastrophic Leaks	20	5.0×10^{-8}
Rupture	100	2.2×10^{-8}
Total		4.72×10^{-7}

Based on this table, leak frequencies for varying pipe sizes can be calculated for a section of the pipe. The resulting leak frequencies calculated are given in **Table 3.26**.

Table 3.26
Failures Rates for Process Piping

Pipe Diameter		Mean Failure Rate
(inches)	(mm)	(per m-year)
0.5	13	3.7×10^{-5}
0.75	19	2.5×10^{-5}
1	25	1.9×10^{-5}
1.5	40	1.2×10^{-5}
2	50	9.3×10^{-6}
3	80	6.3×10^{-6}
4	100	4.6×10^{-6}
6	150	3.1×10^{-6}
8	200	2.3×10^{-6}
10	250	1.9×10^{-6}
12	300	1.5×10^{-6}
14	350	1.3×10^{-6}
16	400	1.2×10^{-6}
18	450	1.0×10^{-6}
20	500	9.3×10^{-7}
24	610	7.7×10^{-7}
36	900	5.2×10^{-7}
48	1200	3.9×10^{-7}

The hole size distribution for pipe failures with respect to cross sectional area and pipe diameter is presented in **Table 3.27**. For the purpose of this study, *small* leaks are considered to have a representative hole size of 1% of the pipe cross sectional area.

Table 3.27

Hole Size Distribution for Pipe Leaks

Hole Size as a % of		Proportion of Failures (%)
Cross-sectional Area (a/A)	Pipe Diameter (d/D)	
1	10	60
5	22	25
20	45	10
100	100	5

It should be noted that all large holes relative to the pipe diameter are considered to be full bore ruptures of the pipe. This is a valid assumption because most larger holes will tend to propagate to full bore ruptures due to the stresses in the pipework.

Pressure Vessels

All pressure vessels are subject to cracks of various sizes. If a crack propagates across the whole of a vessel shell, the contents are released rapidly and a “catastrophic rupture” is said to have occurred. Smaller cracks lead to discharge over a period of time depending on the crack size and the vessel inventory. These are referred to as “leaks”.

Of the many sources of data available, that of Smith and Warwick (1981) is the most useful for the following reasons:

- ♦ The vessel population is precisely defined, being pressure vessels registered for insurance purposes with the Associated Offices Technical Committee.
- ♦ As a qualitative description is given of every failure, it is possible to make an analysis of the failure and to form a judgement as to its relevance to the vessels to be found on a petrochemical site.

Smith and Warwick quote 12 failures covered by catastrophic rupture and 76 by leakage. Of these however, only 2 catastrophic ruptures and 44 leaks can be attributed to the pressure vessel itself.

20,000 pressure vessels were covered by the study giving a total of 310,000 vessel-years. **Table 3.28** gives the screened Smith and Warwick data failure rates for pressure vessels, broken down by cause of failure where known.

This shows that catastrophic ruptures are dominated by operational (pressure) overload. For each of the remaining leak classes, a representative hole size will be used for each class. The hole sizes and frequencies to be used are summarised in **Table 3.29**.

The inventory of a storage vessel often varies with time. If that variation is significant, or the normal inventory is much less than the tank capacity, two or more inventories should be treated as separate failure cases: for example, for a full and for a half-full tank. The frequency split between these will depend on plant operations.

Table 3.28
Summary of Pressure Vessel Failure Statistics

Failure Mechanism	Number of Failures of Size			
	Small Leak (up to 25 mm)	Medium Leak (25 to 50 mm)	Large Leak (50 to 150mm)	Catastrophic Rupture (over 150 mm)
Design Error	2	1	-	-
Material / Construction Defect	5	3	1	-
Mechanical Wear	1	-	-	-
Fatigue	5	3	-	-
Corrosion	1	3	-	-
Corrosion Fatigue	1	-	-	-
Thermal Fatigue	1	-	-	-
Creep	2	-	1	-
Operational Overload	1	2	-	2
Unknown	6	4	1	-

Table 3.29
Summary of Pressure Vessel Failure Rates

Equivalent Hole Size (mm)	Leak Frequency (per year)
5	3.7×10^{-5}
25	$9.6 \times 10^{-53.29}$
100	9.7×10^{-6}
Rupture	6.5×10^{-6}
Total	1.5×10^{-4}

Valves

Valves are a common source of leaks on a process plant. Such leaks are usually from the packing around the valve stem. Leaks are usually minor and the rate of release insignificant when in the context of a safety study. Leak detection is typically carried out before a critical situation develops that may cause a safety problem. However, in some cases the leak may be significant and could cause a hazard to people in the vicinity. With regard to the main body of the valve (valve casing) the wall thickness is generally quite large (compared with process piping) and leaks from the casing are deemed unlikely.

Control Valves

The data given in OREDA (1992) for control valves that are pneumatically operated globe valves (8 to 12 inch valves) records a critical failure rate of 3.89 failures per 10^6 hours, or 3.3×10^{-2} failures per valve-year.

A breakdown of leak frequency by leak size is not given in these sources and thus additional analysis is required. All leaks from the control valves reported by OREDA (1992) are small leaks. Assuming that about 1% of all leaks could be large enough to be relevant to a safety risk study (i.e. above pinhole size). Hence, these leaks have a frequency of 4.0×10^{-4} per year per valve. The distribution of leak sizes is taken to be similar to that of piping. This leak frequency distribution is given in **Table 3.30**.

Table 3.30

Leak Frequencies for Control Valves by Hole Size

Normalized Hole Size (d/D)	Frequency (per year)
0.1	2.6×10^{-4}
0.2	1.0×10^{-4}
0.45	4.0×10^{-5}
Total	4.0×10^{-4}

ESD Valves

The OREDA (1992) gives a frequency of critical external leaks from ESD valves in hydrocarbon service as 0.45 occurrences every 10^6 hours. This gives an annual frequency of 3.9×10^{-3} leaks per valve year.

Again, the leak frequency is not broken down by leak size. The same assumption is made that about 1% of all leaks could be large enough to be relevant to a safety risk study. Hence, these leaks have a frequency of 3.9×10^{-5} per valve-year. The distribution of leak sizes is taken to be similar to that for control valves as given in **Table 3.31**.

Table 3.31

Leak Frequencies for ESD Valves by Hole Size

Normalised Hole Size (d/D)	Frequency (per year)
0.1	2.5×10^{-5}
0.2	9.8×10^{-6}
0.45	3.9×10^{-6}
Total	3.9×10^{-5}

Shut off Valves

The OREDA (1992) gives a frequency of critical external leaks from shut-off valves in hydrocarbon service as 0.82 occurrences every 10^6 hours. This gives an annual frequency of 7.2×10^{-3} leaks per valve year.

Again, the leak frequency is not broken down by leak size. The same assumption is made that about 1% of all leaks could be large enough to be relevant to a safety risk study. Hence, these leaks have a frequency of 7.2×10^{-5} per valve-year. The distribution of leak sizes is taken to be similar to that for control valves as given in **Table 3.32**.

Table 3.32

Leak Frequencies for Shut-Off Valves by Hole Size

Normalised Hole Size (d/D)	Frequency (per year)
0.1	4.7×10^{-5}
0.2	1.8×10^{-5}
0.45	7.2×10^{-6}
Total	7.2×10^{-5}

Check Valves

Check valves do not have any external mechanisms which are a likely source of a leak. All of the mechanisms of the valve are kept within the valve casing. The only sources of leaks are from the valve casing itself or from the flanges on the valve. Hence, when considering leaks from check valves, only the flanges associated with the valve are taken into account. Flange failure frequencies are detailed in next Section.

Flanges

For flanges, industrial sources give figures covering the range of 6×10^{-4} (in LPG service) to 1.6×10^{-4} (in liquid ammonia service) failures per year. Whittle (1993) quotes a lower failure rate of 6.2×10^{-5} failures per year, while the failure rate quoted by Sooby (1992)

is even lower by over an order of magnitude of 3.3×10^{-6} failures per year. Since the quality of the pipe flanges varies enormously with application, it seems sensible to regard this range as a reflection of flange and gasket quality.

A failure frequency of 1×10^{-5} per year is used for high quality flanges (e.g. raised face, ring type, or grey lock flanges used in high pressure, high temperature service).

An analysis of flange failure hole sizes shows then to be small. The analysis shows that the maximum equivalent hole diameter for a flange leak from a 6 inch pipe is 12 mm. It has been assumed that for pipes greater than 6 inch in diameter that 10% of all flange leaks contribute to leaks in the range of 10 to 50 mm (i.e. 25 mm holes). For pipes of 6 inch diameter or smaller all leaks are taken to fall into the 0 to 10 mm hole size range (i.e. 5 mm holes). **Table 3.33** summarises the leak frequencies for flanges by hole size.

Table 3.33

Summary of Flange Failure Rates

Hole Size (mm)	Frequency (per year)
5	9.0×10^{-5}
25	1.0×10^{-5}
Total	1.0×10^{-4}

Pumps

The NPRDS Annual Reliability Report (1981) gives the most detailed leak data records for pumps. It also covers one of the largest operational time spans, covering 3258 pump-years operational experience. **Table 3.34** summarises the analysis of this data set.

Most of the pump failures (63%) were detected whilst the system was in service, and only this fraction of failures are used below. 59% of the pump failures are leaks, which are in line with data given by a confidential source stating 60%.

As multiple seals have only been in common use since the 1980's, we assume the population analysed in NPRDS primarily are single seal pumps. No further information is presently available concerning the failure mode and hole size distribution for the reported pump failures. Certain assumptions have therefore been made:

- ◆ The failure modes “leak” and “crack” contribute to the 5 mm leak category. The former relates to seal leaks, the latter is considered to be a common mode failure.

- ♦ The failure modes “breach”, “collapse” and “fracture/break” contribute to the 25mm leak category. All failures are considered as common-mode failures.

In principle, all leak relevant failure modes fall into two categories, i.e. seal or pump casing failures. The difference between single seal and double seal leak frequencies is considered only to apply for 5 mm leaks, as common mode failures (i.e. related to casing) are more significant for larger leaks than seal problems. The 5 mm leak frequency for double seal pumps is estimated assuming the same seal leak frequency for inner and outer seal, i.e. the same seal leak contribution as for a single seal. However, failures relating to casing (i.e. crack failures) have been assigned as a common mode failure:

$$\lambda \text{ (double seal)} = ((158/2139) \times 0.63)^2 + 18/2139 = 7.5 \times 10^{-3}$$

The estimation of 25 mm leak frequencies are somewhat limited by the restricted information available on the reported events. The calculated frequency indicates 4×10^{-3} , but as some of these may belong to the smaller leak category, we assume the same leak frequency in the order of 10^{-3} for single and double seals.

Table 3.34

Failure Mode Distributions For Pumps In Nuclear Industries

Type of Pump	Failure Mode						Total Failures	Operational/ Calendar Time (yr.)
	Leak	Crack	Breach	Collapse	Fracture/ Break	Other		
Axial	1					2	3	66 / 230
Centrifugal	158	18	3	2	10	143	334	2139 / 6007
Diaphragm	2					6	8	35 / 105
Gear	1						1	70 / 313
Reciprocating	259	11	1	1	26	40	338	196 / 521
Radial						2	2	14 / 37
Rotary	7				1	20	28	138 / 443
Vane						8	8	28 / 60
Jet						4	4	492 / 586
Other						4	4	74 / 227
Undefined							0	6 / 35
Total	428	29	4	3	37	229	730	3258/8564

The leak frequency from the combined 4" leak and rupture situation is based on information by Lees (1980) (quoting the SRS database), and is estimated at 10^{-4} per year. If we assume the same operational pump experience time in the period 1981-1989 as from

July 1974 until December 1980 as given in NPRDS (1981), we have about 5000 item years operational experience for centrifugal pumps, or about 10000 pump years for all pumps. The leak frequencies for reciprocating pumps are estimated in the same way as for centrifugal pumps, based on available NPRDS data. Rupture frequency of reciprocating pumps is assumed to be one order of magnitude below the one applied for centrifugal pumps.

The pump leak frequencies used in this risk analysis are summarised in **Table 3.35**.

Table 3.35
Leak Frequencies For Pumps

Equivalent Hole Size (mm)	Leak Frequency (per item year)			
	Centrifugal		Reciprocating	
	Single Seal	Double Seal	Single Seal	Double Seal
5	5.2×10^{-2}	7.5×10^{-3}	0.868	0.728
25	1.0×10^{-3}	1.0×10^{-3}	1.0×10^{-2}	1.0×10^{-2}
100 or Rupture†	1.0×10^{-4}	1.0×10^{-4}	1.0×10^{-3}	1.0×10^{-3}
Total	0.011	0.001	0.879	0.739

† Maximum equivalent hole size for pumps is considered to be 100 mm.

Compressors

The reported leaks were categorized as follows:

- ◆ 15 considered in 0-10 mm range
- ◆ 1 categorized as 25 mm leak frequency

The number of stages was estimated by assuming 2.5 stages per compressor.

Leaks in the 100 mm to rupture range were estimated at 10% of the 25 mm leak frequency.

The compressor failure rates are summarized in **Table 3.36**.

Table 3.36
Compressor Failure Rates

Hole Size	Frequency (per stage-year)	Probability Distribution
5mm	0.013	0.093
25 mm	8.6×10^{-4}	0.06
100 mm/Rupture	8.6×10^{-5}	0.01

Heat Exchanger, Shell and Tube

External leaks from a shell and tube heat exchanger can be caused by:

- ♦ Leakage from the shell directly to atmosphere.
- ♦ Tube rupture-causing overpressure inside shell, which leads to external leak.

Direct Shell Leakage

The shell-side of a heat exchanger is essentially a pressure vessel. Due to lack of historical data on external shell leaks it has been assumed that the leak frequency is the same as for pressure vessels. The limited historical experience on heat exchanger failures are discussed briefly below, including heat exchangers generally as well as specific shell and tube heat exchanger experience.

Leakage Due to Tube Rupture

The data source quotes tube failures of 2.4×10^{-5} per ft year, and tube leaks at 5.4×10^{-6} per ft year. Based on this we estimate the frequency of tube leak per tube ft year to be on the order of 10^{-5} . Using the leak distributions for 3/4 inch and 1 inch pipe, 10% of leaks will be ruptures. Perry and Chilton (1973) state typical tube length to be 16 feet, and the number of tubes we assume from OREDA to be about 300. Thus, annual tube rupture frequency can be estimated to be:

$$\begin{aligned} \text{Rupture Frequency} &= 10^{-5} \frac{\text{tube leak}}{\text{ft} - \text{year}} \times 10\% \frac{\text{rupture}}{\text{leak}} \times 16 \frac{\text{ft}}{\text{tube}} \times 300 \frac{\text{tubes}}{\text{ht exchanger}} \\ &= 4.8 \times 10^{-3} \text{ tube ruptures/year} \end{aligned}$$

We assume that 50% of the tube ruptures are severe enough to require pressure relief to avoid external leakage. Failure of the shell protection system can lead to external leakage. Failure of the system can be due to a defect in the system (e.g. a pressure relief device sticks closed) or it may be due to local effects where the pressure rises far too quickly for the relief device to operate. A failure demand probability of 1% is assumed. Thus, the (external) leak frequency originated from tube ruptures will be:

$$\begin{aligned} \text{Shell Leak Frequency} &= 4.8 \times 10^{-3} \frac{\text{tube ruptures}}{\text{Year}} \times 50\% \frac{\text{relief demand}}{\text{tube rupture}} \times 0.1 \frac{\text{shell leaks}}{\text{relief demand}} \\ &= 2.4 \times 10^{-5} \frac{\text{leaks}}{\text{year}} \end{aligned}$$

The hole size distribution as for pressure vessels is then applied to estimate a distribution of leak sizes.

Historical data from EPRI (1981) for similar type of equipment gives the following tube burst frequency:

- ♦ Closed cooling heat exchanger: $2.5 \times 10^{-3}/\text{year}$
- ♦ Condenser: $5 \times 10^{-3}/\text{year}$

Other sources on heat exchangers have refer to failures only. OREDA (1994) gives leak frequencies in the range 0.046 to 0.561/year, but is only based on a total of 516 calendar year experience.

Arulanantham and Lees (1981) present data on heat exchangers generally from four chemical plants based on 5950 vessel-years experience, giving a total failure rate of $1.7 \times 10^{-3}/\text{year}$. As a comparison to the Summary, our estimated total leak frequency is one order of magnitude below this total failure rate.

Summary

The shell failure rates are taken from those for pressure vessels and the tube failures are taken from the analysis above. This results in the frequencies in **Table 3.37**.

Table 3.37

Exchanger Failure Rates

Hole Size	Direct Shell Leak (per year)		Shell Leak from Tube Rupture (per year)		Total External Leak (per year)	Probability Distribution
	Frequency	Probability Distribution	Frequency	Probability Distribution		
5 mm	3.7×10^{-5}	0.25	6.0×10^{-6}	0.25	4.3×10^{-5}	0.25
25 mm	9.6×10^{-5}	0.64	1.5×10^{-5}	0.62	1.1×10^{-4}	0.65
100 mm	9.7×10^{-6}	0.065	1.7×10^{-6}	0.071	1.1×10^{-5}	0.065
Rupture	6.5×10^{-6}	0.043	9.6×10^{-7}	0.04	7.5×10^{-6}	0.044

Atmospheric Storage Tanks

Derivation of Failure Frequency

A review of literature produced reports of four catastrophic tank failures in the US in the last twenty years:

- ♦ 1971 (location unknown), brittle fracture caused loss of 66,000 bbl crude oil
- ♦ 1988 Ashland Oil, PA, brittle fracture caused loss of 96,000 bbl diesel

- ♦ 1977 corrosion failure of sulfuric acid storage tank led to loss of 12,000 bbl acid, Allied Chemical, Geismar, LA
- ♦ 1983 corrosion failure of sulfuric acid storage tank led to loss of 12,000 bbl acid, Essex Chemicals, Baltimore, MD.

One could argue that this set of data may be incomplete. It is difficult to imagine, however, that a catastrophic failure of a large storage tank could escape the attention of the US news media.

The number of tank years which provided the basis for the four failures was estimated from literature to be about 11,600 large storage tanks. Large, in this case, is defined as having a capacity ranging from 10,000 to 100,000 barrels. These tanks were found to have a mean age of around 17 years. Thus, the total tank years was found to be 197,000.

Dividing the number of failures by the number of tank years yields a catastrophic failure frequency of 2.0×10^{-5} per tank-year.

Tank Fire Frequencies

The reported atmospheric tank fire frequency worldwide and more specifically from South East Asia has been reviewed. This covered cone roof tanks and both rim seal and full surface fires for floating roof tanks. The importance of obtaining complete data was emphasized, as incomplete sets when combined with the true tank population would generate a lower than actual fire frequency. Full reporting of rim fires in the general literature from which no significant damage results is unlikely. Although limited, a selection of complete data from North America and Europe was obtained and reviewed. This produced a floating roof tank fire frequency of 2.4×10^{-3} per year. Only 1 of the 12 fires was a full surface fire.

South East Asia data were collected from all OPITSC members and this generated fire frequency values of:

Cone roof tank = 1.8×10^{-4} per year

Floating roof tank = 5.6×10^{-3} per year (rim and full surface fires total)

Based on the number of tank years experience the higher floating roof tank frequency in South East Asia compared to Aishwariya/Europe was found to be statistically significant. This is considered to be attributable mainly to the more difficult environmental

conditions in South east Asia (lightning storms, temperature, humidity) than in temperate climates.

The frequency of rim seal fires was found to exceed full surface fires by a ratio of 8 to 1. In general, it should not be assumed that full surface fires result from escalations of rim seal fires. Although this can happen, full surface fires can occur immediately due to sunken or flooded roofs.

A review of larger reported tank-fire incidents worldwide has been carried out and it has been found that there have been no serious fatality incidents in advanced countries (characterised by modern technology, knowledgeable management, and good emergency services) in the past 30 years. However, three serious fatality tank fires have occurred elsewhere: a boilover incident in Venezuela, a pool fire in Poland, and we understand, a serious fatality tank fire incident in China of which we have no details.

Once a full surface fire is established, a review of larger fire incidents worldwide shows that a little less than half of these (about 45%) escalate to involve neighbouring tanks. Boilover is mentioned in about 7% of these tank fire reports (but this is a limited sample of more serious reported incidents).

3.15 Probability of Immediate Ignition and Individual Risk Assessment Criteria

For the frequency assessment it is necessary to estimate the probability of ignition if a leak occurs. Ignition of a leak may occur either at the point of leak or at some distance from it. The cause of ignition may be the leak itself (e.g., a leak may generate static electricity) or an ignition source which then gives a spark and ignites the leak.

The information available on probability of ignition is mostly in the form of expert estimates. **Table 3.38** details the immediate ignition probabilities used in this analysis. This data has been obtained from E&P Forum.

Table 3.38

Probability of Ignition for Leaks of Flammable Fluids

Leak Rate	Probability of Ignition	
	Gas	Liquid
Minor (< 1kg/s)	0.01	0.01
Major (1 to 50 kg/s)	0.07	0.03
Massive (>50 kg/s)	0.30	0.08

Table 3.39

The ADNOC Individual Risk Assessment Criteria

ADNOC Acceptability Criteria	Maximum Individual Risk Criteria for Workers		Maximum Individual Risk Criteria for Public
	Existing Installation	New Installation	
Benchmark	$IR < 2 \times 10^{-4}$	$IR < 2 \times 10^{-5}$	$IR < 1 \times 10^{-5}$
Unacceptable	$IR > 1 \times 10^{-3}$	$IR > 1 \times 10^{-3}$	$IR > 1 \times 10^{-4}$
Acceptable	$IR < 1 \times 10^{-5}$	$IR < 1 \times 10^{-5}$	$IR < 1 \times 10^{-6}$

3.16 Risk Assessment

3.16.1 Gas Pipeline

The risk transect are plot for a gas pipeline for a scenario of jet fire. Individual risk for a pipeline at a given point is the product of probability of jet fire and population present up to the distance of 165m (Refer **Table 3.16**), either side of pipeline. Risk transect is the graphical presentation of individual risk v/s pipeline length.

Table 3.40

Pipeline Route Crossing Details

Sr. No.	Type of Crossing	Chainage (km)	Latitude (m)	Longitude (m)
1.	Take off point	0/0	25°53' 00.9"	72°35' 03.41"
2.	NH-112 (Barmer-Baithu)	2/5	25°51' 54.5"	71°36' 48.5"
3.	NW Railway (Barmer-Baithu)	2/6	25°51' 51.4"	71°36' 48.5"
4.	Metalled Road (Kawas-Cairn Terminal)	7/8	25°47' 28.3"	71°40' 18.4"
5.	Asphalted Road (Chawa-Baithu)	19/1	25°44' 50.7"	71°40' 23.8"
6.	Asphalted Road (Chawa-Dandali)	19/4	25°44' 34.5"	71°40' 32.8"
7.	SH-16 (Barmer-Sindari)	27/0	25°41' 04.5"	71°42' 31.3"
8.	Asphalted Road (Nimbalkot-Hodu)	43/3	25°32' 19.4"	71°42' 28.3"
9.	Metalled Road (Nimbalkot-Koslu)	51/0	25°30' 46.0"	71°44' 17.3"
10.	Terminal Point (CPF-2, Saraswathi field)	64/3	25°23' 00.19"	71°48' 17.17"
11.	SH-28 (Kudala-Bhatala)	64/7	25°22' 54.2"	71°48' 30.5"
12.	Asphalted Road (Jalikheda-New Undri)	73/8	25°18' 32.2"	71°47' 31.8"
13.	Terminal (WP-3, Raageswari field)	76/9	25°17' 25.0"	71°46' 18.0"

Table 3.41

Individual Risk along the Pipeline

Sr. No.	Chainage (km)	Population Considered	Individual Risk (Rupture Scenario)
			Frequency of Jet Fire 4.5E-07
1	0/0	0	0
2	2/5	25	1.12E-05
3	2/6	30	1.35E-05
4	7/8	40	1.8E-05
5	19/1	5	2.25E-06
6	19/4	20	9.0E-06
7	27/0	0	0
8	43/3	15	6.75E-06
9	51/0	0	0
10	64/3	15	6.75E-06
11	64/7	35	1.57e-05
12	73/8	40	1.8E-05
13	76/9	45	2.02E-05

3.16.2 Risk Transect for Rupture Scenario

Frequency of failure of 12" pipeline is 1.5E-06 f/m-yr. (refer **Table 3.26**) and Probability of occurrence of jet fire for rupture of pipeline is 4.5E-07 (refer **Fig. 3.13** Event Tree for Frequency of Hazardous Consequence Full Bore Rupture of Pipeline). Individual Risk is calculated at every chainage and values of Individual Risk are presented in **Table 3.41**. The Risk Transect is shown in **Fig. 3.14**.

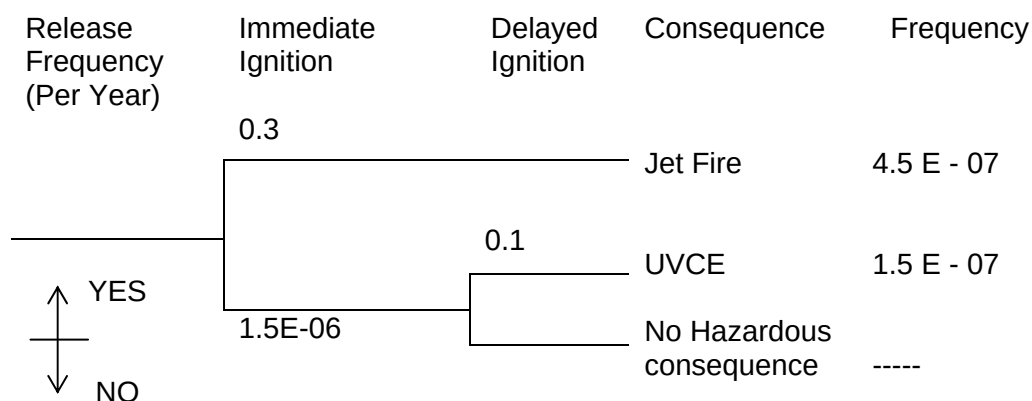


Fig. 3.13: Event Tree for Frequency of Hazardous Consequence Full Bore Rupture of Pipeline

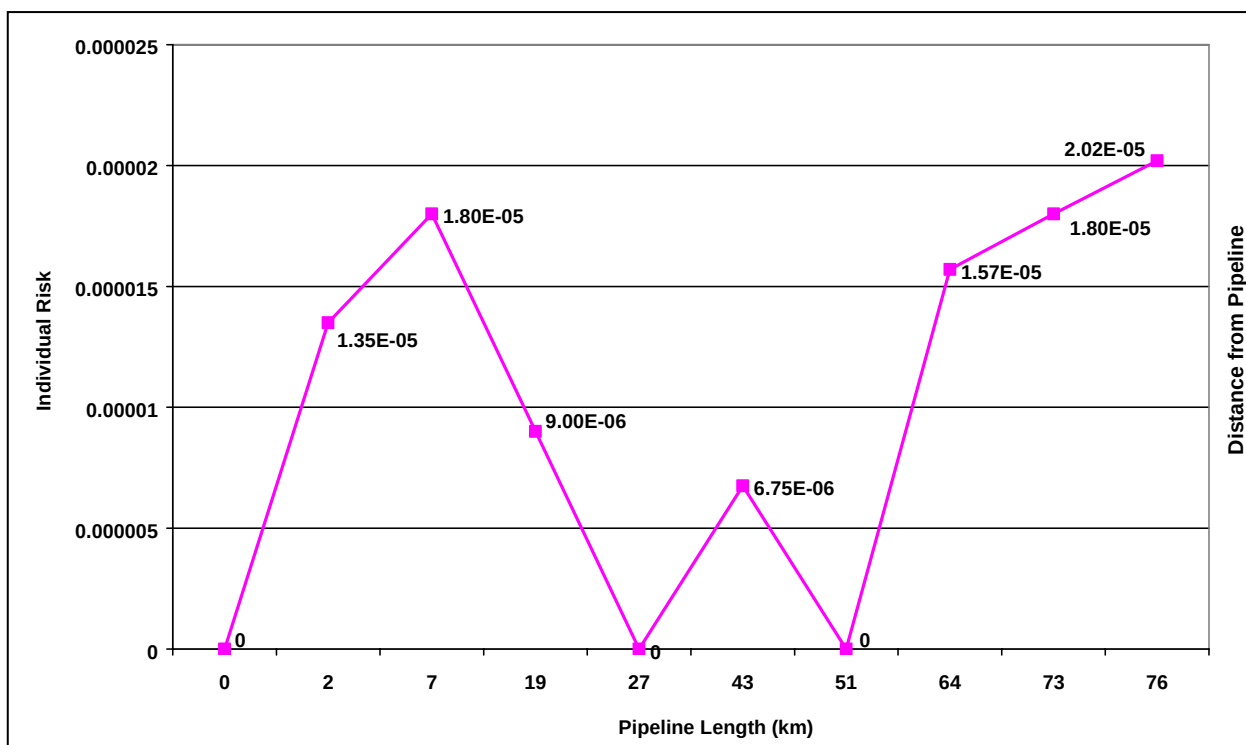


Fig. 3.14: Risk Transect for Pipeline (Rupture Scenario)

3.16.3 CTF Mangala & Aishwariya Fields

The Individual risk due to CTF at Mangala and Aishwariya Field is calculated with the help of SAFETI Software. 30 persons were considered as a population present within the CTF in a shift and frequency of catastrophic rupture of crude oil storage tanks and diluent storage tanks is taken from **Table 3.29**. The individual risk for CTF is vary from 10E-06 to 10E-08 and it is concluded that the risk due to CTF is acceptable for workers as well as for the public as per **Table 3.39**. The individual risk contour for CTF at Mangala and Aishwariya Field is presented in **Fig. 3.15**.

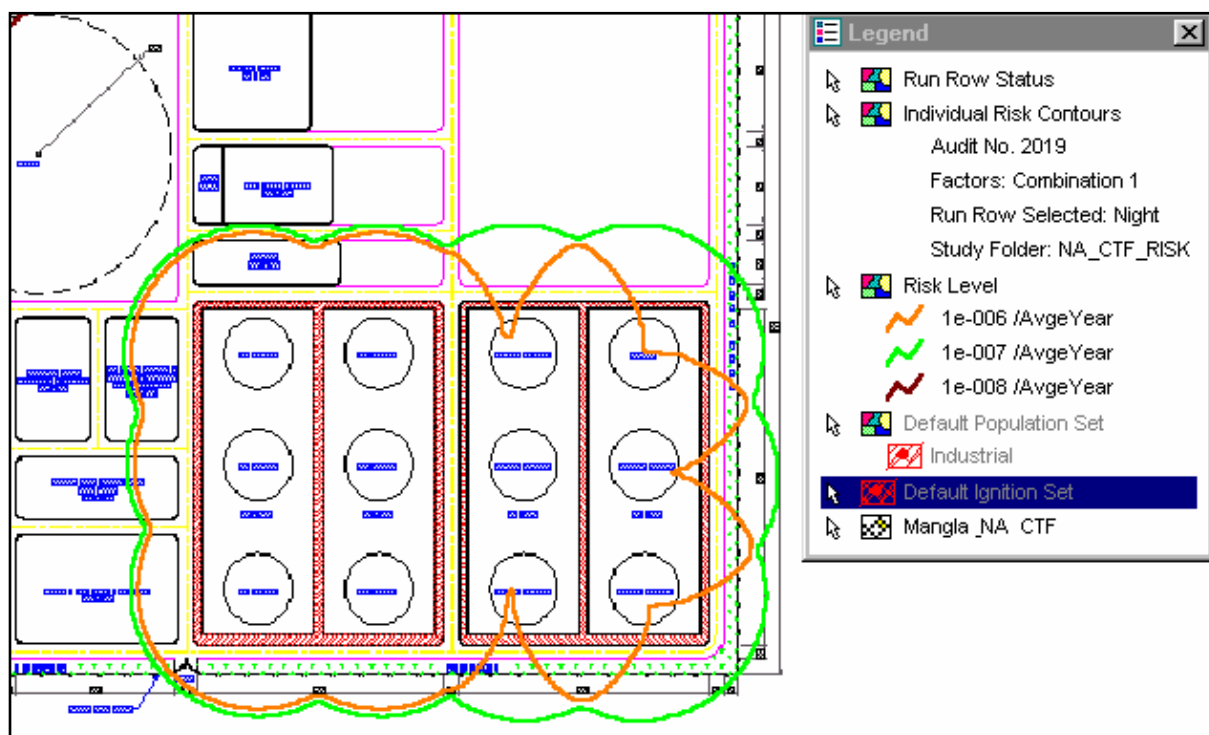


Fig. 3.15: Individual Risk Contour for CTF at Mangala and Aishwariya Field

3.16.4 GGS Mangala & Aishwariya Fields

The Individual risk due to GGS at Mangala and Aishwariya Field is calculated with the help of SAFETI Software. 20 persons were considered as a population present within the GGS in a shift and frequency of catastrophic rupture of oil buffer tanks is taken from **Table 3.29**. The individual risk for GGS is vary from $10E-06$ to $10E-09$ and it is concluded that the risk due to GGS is acceptable for workers as well as for the public as per **Table 3.39**. The individual risk contour for GGS at Mangala and Aishwariya Field is presented in **Fig. 3.16**.

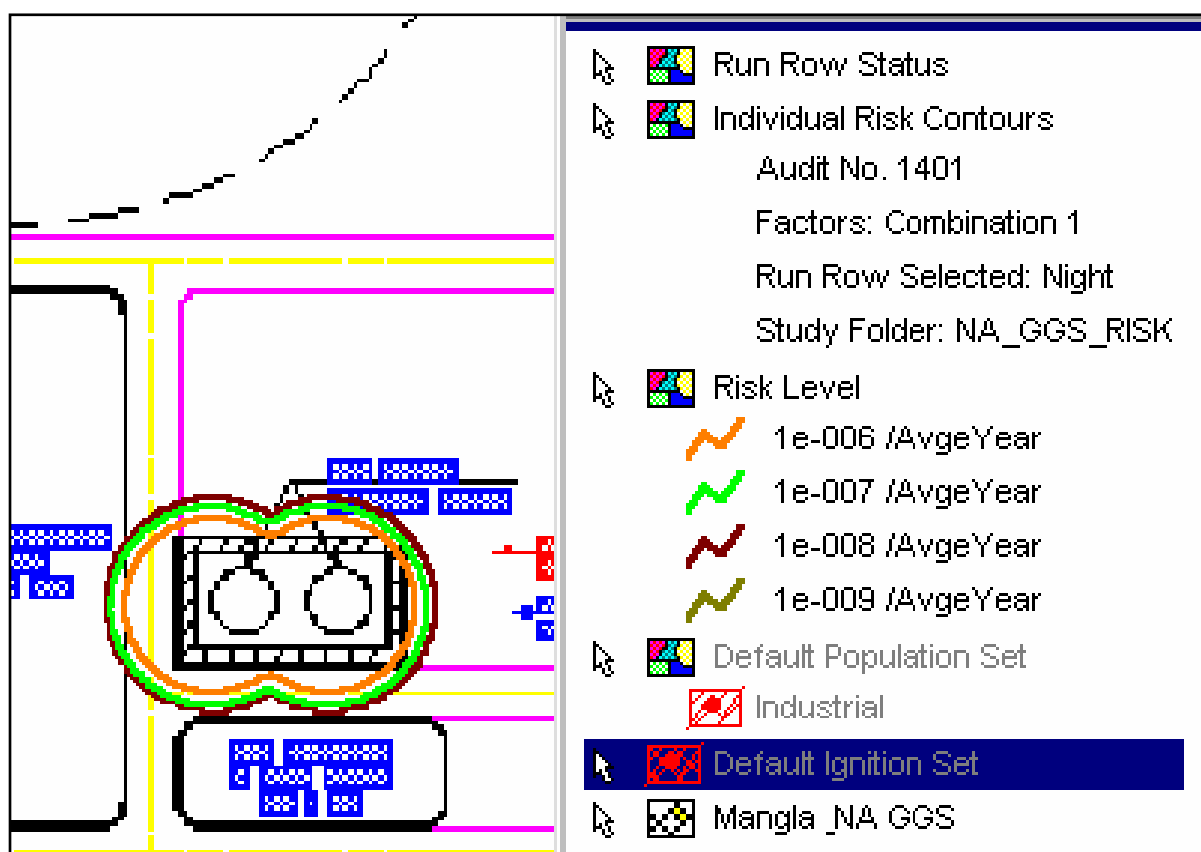


Fig. 3.16: Individual Risk Contour for GGS at Mangala and Aishwariya Field

3.16.5 GGS CTF Saraswati Fields

The Individual risk due to GGS CTF at Saraswati Field is calculated with the help of SAFETI Software. 20 persons were considered as a population present within the GGS CTF in a shift and frequency of catastrophic rupture of oil buffer tanks and crude oil storage tanks is taken from **Table 3.29**. The individual risk for GGS CTF is vary from 10E-06 to 10E-09 and it is concluded that the risk due to GGS CTF is acceptable for workers as well as for the public as per **Table 3.39**. The individual risk contour for GGS CTF at Saraswati Field is presented in **Fig. 3.17**.

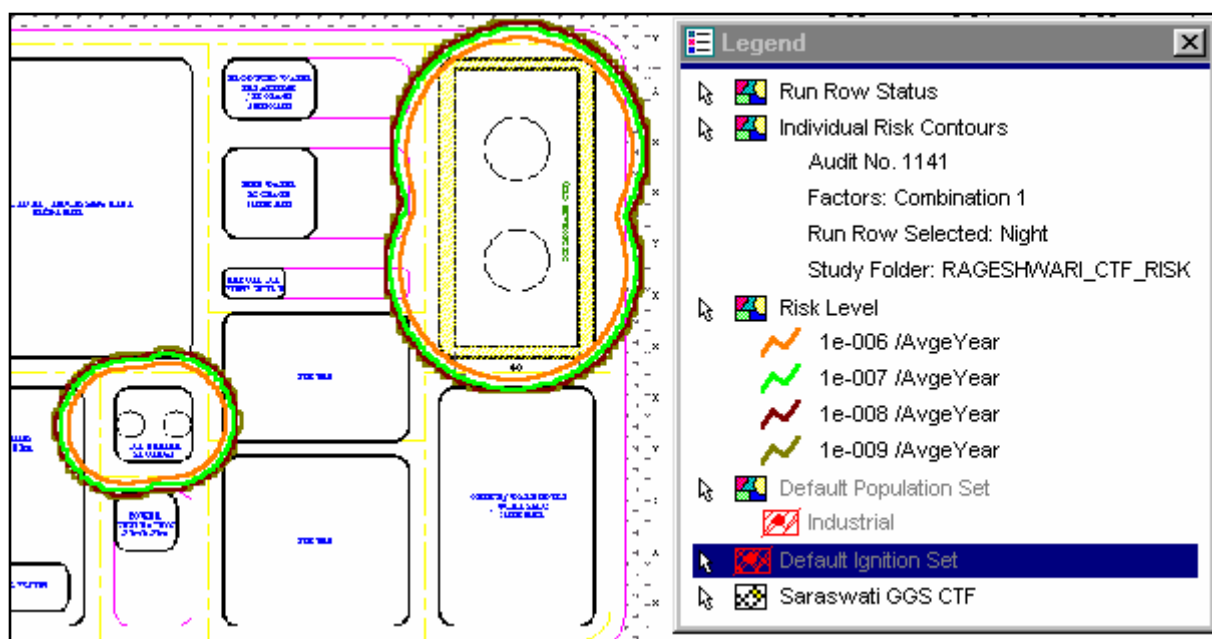


Fig. 3.17: Individual Risk Contour for GGS CTF at Saraswati Field

3.16.6 Power Plant

The Individual risk due to Power Plant is calculated with the help of SAFETI Software. 20 persons were considered as a population present within the Power Plant in a shift and frequency of catastrophic rupture of crude oil tanks is taken from **Table 3.29**. The individual risk for Power Plant is vary from 10E-06 to 10E-09 and it is concluded that the risk due to Power Plant is acceptable for workers as well as for the public as per **Table 3.39**. The individual risk contour for Power Plant is presented in **Fig. 3.18**.

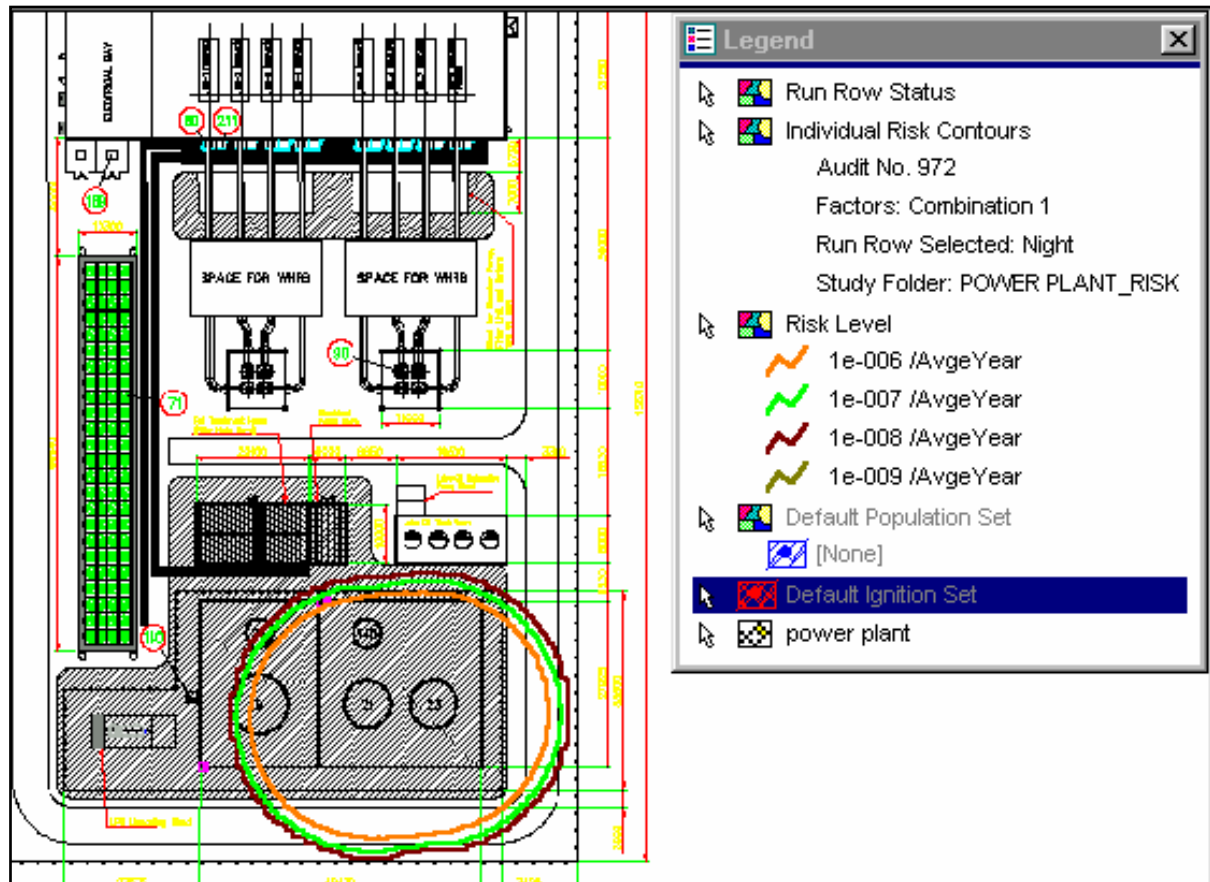


Fig. 3.18: Individual Risk Contour for Power Plant

3.16.7 Well Blowout

The Individual risk due to well blowout is calculated with the help of SAFETI Software. 20 persons were considered as a population present within the well pad in a shift and frequency of well blowout is taken from **Table 3.19**. The individual risk due to well blowout is vary from 10E-06 to 10E-09 and it is concluded that the risk due to well blowout is acceptable for workers as well as for the public as per **Table 3.39**. The individual risk contour for well blowout scenario is presented in **Fig. 3.19**.

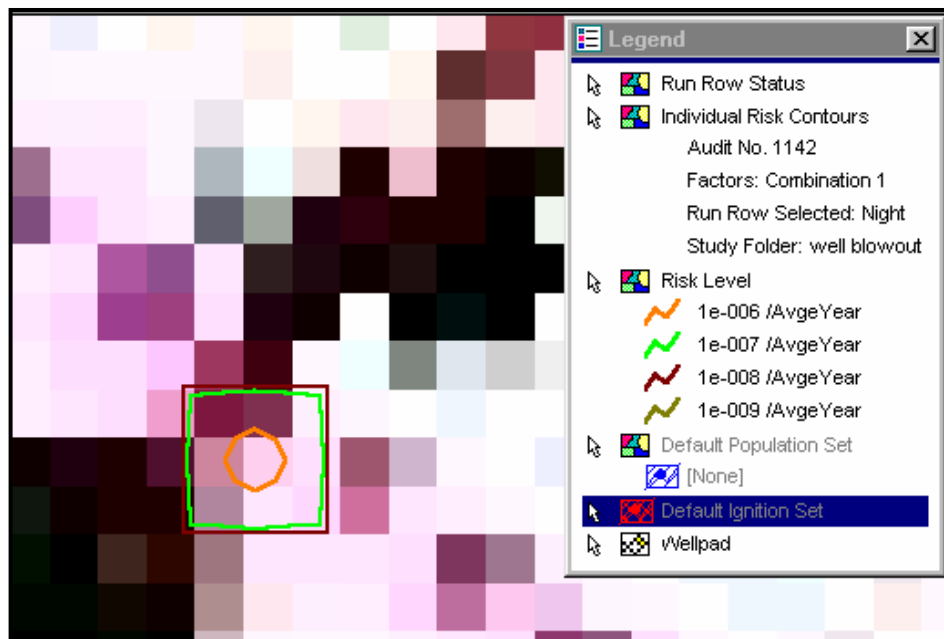


Fig. 3.19: Individual Risk Contour for Well Blowout

Chapter 4

Risk Mitigation Measures

Risk involves the occurrence of an accident consisting of an event or sequence of events. The impact zones in case of such accidents are computed through Maximum Credible Accident (MCA) Analysis. Hazard identification step is a key in developing an understanding of the contributors to the risk of operating a particular system or process. Once the hazards are identified, safeguards can be recommended, which can either prevent an event from occurring or reduce the consequences, if at all the event occurs.

4.1 Summary of Findings

4.1.1 Risk due to CTF Mangala & Aishwariya Fields

The individual risk for CTF is vary from $10E-06$ to $10E-08$ and it is concluded that the risk due to CTF is acceptable for workers as well as for the public

4.1.2 Risk due to GGS Mangala & Aishwariya Fields

The individual risk for GGS is vary from $10E-06$ to $10E-09$ and it is concluded that the risk due to GGS is acceptable for workers as well as for the public.

4.1.3 Risk due to GGS CTF Saraswati Fields

The individual risk for GGS CTF is vary from $10E-06$ to $10E-09$ and it is concluded that the risk due to GGS CTF is acceptable for workers as well as for the public.

4.1.4 Risk due to Power Plant

The individual risk for Power Plant is vary from $10E-06$ to $10E-09$ and it is concluded that the risk due to Power Plant is acceptable for workers as well as for the public

4.1.5 Risk due to Well Blowout

The individual risk due to well blowout is vary from $10E-06$ to $10E-09$ and it is concluded that the risk due to well blowout is acceptable for workers as well as for the public.

4.2 Recommendations

4.2.1 Drilling Operations

A majority of accidents occur during drilling operation on the drill floor and may be associated with moving heavy tubular, which may strike or crush personnel. Being struck by objects, falling and crushing make up maximum occupational risk of fatality. Mechanical pipe handling, minimizing the requirement of personnel on the drill floor exposed to high level of risk, may be an effective way of reducing injuries and deaths. Good safety management, strict adherence to safety management procedures and competency assurance will reduce the risk. Some of the areas in drilling operations where safety practices are needed to carry out jobs safely & without causing any injury to self, colleagues and system are:

Maintenance of Mud Weight

It is very crucial for the safety of drilling well. Drilling Mud Engineer should check the ingoing & outcoming mud weight at the drilling well, at regular intervals.

If mud weight is found to be less, barytes should be added to the circulating mud, to raise it to the desired level. Failure to detect this decrease in level may lead to well kick & furthermore, a well blow out, which can cause loss of equipments & injury to or death of the operating personnel.

Monitoring of Active Mud Tank Level

Increase in active tank level indicates partial or total loss of fluid to the well bore. This can lead to well kick. If any increase or decrease in tank level is detected, shift personnel should immediately inform the Shift Drilling Engineer & take necessary actions as directed by him.

Monitoring of Hole Fill-up / Return Mud Volume during Tripping

During swabbing or pulling out of string from the well bore, the hole is filled with mud for metallic displacement. When this string runs back, the mud returns back to the pit. Both these hole fill up & return mud volumes should be monitored, as they indicate any mud loss or inflow from well bore, which may lead to well kick.

Monitoring of Inflow

Any inflow from the well bore during tripping or connection time may lead to well kick. So, it is needed to keep watch on the flow nipple during tripping or connection time.

Monitoring of Background / Trip Gas

Increase in background gas or trip gas indicates insufficient mud weight against drilled formation. Such indications should be immediately brought to the notice of the Shift Drilling Engineer.

For total safety of such operations, each team member must religiously follow the safety aspects pertaining to respective operational area. If every team member starts working with this attitude, zero accident rate is not a distant dream.

Drilling operation is a team effort and success of such an operation depends upon the sincerity, efficiency & motivation of all team members. Safety in such operations is not the duty of a single person, but it is everyone's job.

The use of protective fireproof clothing and escape respirators will reduce the risk of being seriously burnt. In addition, adequate fire fighting facilities and first aid facilities should be provided, in case of any emergency.

Risk reducing measures include kick simulation training for personnel, presence of well trained drillers and mud engineers, and strict adherence to safety management procedures and good well control procedures.

4.2.2 Pipeline Transportation of Gas

Full-bore rupture of the pipelines has a very low frequency as compared to leakage, which is generally considered as the major loss scenario. The leakage can result in a jet fire leading to thermal radiation effects. Such jet fires are likely only at valve stations and above ground pipeline. There is no fire hazard from the buried section of the pipeline.

Following specific recommendations are suggested in order to enhance the safe handling and transportation of natural gas and crude oil:

- ◆ Hydrocarbon detectors are recommended at strategic locations
- ◆ Sectionalizing valves are recommended at source and destination for isolating the pipeline after detecting leaks, so that corrective action could be taken by stopping the gas/ oil supply

- ◆ Indication boards should be provided along the road where the pipeline is crossing the road
- ◆ As per OISD standard 141, the location of an underground pipeline when running parallel to an existing underground pipeline, should be at a minimum clear distance of 5 m from the existing underground pipeline.
- ◆ 3-layer polyethylene coating for the pipelines and outlet lines should be provided for protection against external corrosion
- ◆ Shut off and isolation valves should be easily approachable in emergencies
- ◆ Cathodic protection by way of impressed current for the pipeline should be provided for prevention of corrosion
- ◆ Appropriate anticorrosion material should be provided at the welds to prevent corrosion
- ◆ The pipelines should be hydraulically tested to a pressure of at least 1.5 times the design pressure before putting into operation
- ◆ The pipeline should be inspected regularly and the same should be scheduled in DMP
- ◆ Effective Emergency response plan for the entire route of the pipeline
- ◆ The Disaster Management plan (offsite) evolved specific to the particular locations / section areas with local features incorporated in the plan.

4.2.3 Gas Gathering Station and Central Tank Farm

- ◆ Hydrocarbon detectors are recommended in gas processing facilities and CTF
- ◆ Surrounding population (including all strata of society) should be made aware of the safety precautions , to be taken in the event of any mishap in the plant
- ◆ Critical switches and alarms should always remain online
- ◆ The equipments / storage should be hydraulically tested to a pressure of at least 1.5 times the design pressure before putting into operation
- ◆ The pipeline/ equipments should be monitored continuously for identifying leakages and have control systems which should be capable of closing down

transmission of oil and gas automatically, if ever required

- ◆ Every storage tank, including its roof and all metal connections, should be electrically continuous and be effectively earthed as per OISD Std. 108
- ◆ Hydrocarbon detectors may be installed in the tank farms with remote alarms in control stations as per OISD Std. 108
- ◆ Fire water requirements should be decided as per guidelines given in OISD Std. 116
- ◆ Fire proofing materials and systems should be applied as per OISD Std. 164.

4.2.4 Power Plant

- ◆ Hydrocarbon detectors are recommended in power plant
- ◆ Surrounding population (including all strata of society) should be made aware of the safety precautions , to be taken in the event of any mishap in the plant
- ◆ Critical switches and alarms should always remain online
- ◆ The equipments should be hydraulically tested to a pressure of at least 1.5 times the design pressure before putting into operation
- ◆ The pipeline/ equipments / storage loading unloading lines should be monitored continuously for identifying leakages and have control systems which should be capable of closing down transmission of oil and gas automatically, if ever required
- ◆ Every storage tank, including its roof and all metal connections, should be electrically continuous and be effectively earthed as per OISD Std. 108
- ◆ Hydrocarbon detectors may be installed in the tank farms with remote alarms in control stations as per OISD Std. 108
- ◆ Fire water requirements should be decided as per guidelines given in OISD Std. 116
- ◆ Fire proofing materials and systems should be applied as per OISD Std. 164.

Chapter 5

Disaster Management Plan

5.1 Need for Disaster Management Plan

Hydrocarbons occupy an important segment of our economy and are also the source of large benefits to the society. In recent years, there has been a rapid increase in the use of natural gas in industries and at the domestic front. Use of cleaner fuels has resulted in increased use of natural gas as fuel in electricity generation and transportation. However, natural gas is highly flammable and ignition results in flash fire, as well as confinement of vapours may lead to explosion. Thus, extreme care is essential while handling natural gas at all stages of transportation and handling.

The hazardous substances could be the source of potential danger to life, property and environment, if not stored or handled properly. Some of the major disasters occurred at Bhopal, Mexico and other parts of the world in the last few decades have made people all over the world concerned about the dangers of chemical accidents. Thus, it is mandatory for each industrial establishment, isolated storage installations and transporters to notify the persons working therein, the public and the Government, regarding the details of the chemical being used or stored and the on-site emergency preparedness in case of any such event. Occurrence of such accidents makes it essential for the Central and State Government agencies as well as the local authorities to be prepared to help mitigate and assist during such eventualities.

It is the Company's policy and corporate responsibility to ensure personnel safety,

conserve natural resources and the environment and protect property. In order to achieve the highest levels of safety it is the Company's policy to maintain and continuously improve the capability for a rapid and effective response to all emergencies, which may affect its operations. In pursuit of this policy, the Company recognizes that emergencies can occur in spite of rigorous and ongoing preventive measures. It shall, therefore, prepare and revise DMP including emergency procedures, establish an Emergency Response Group (ERG) to implement them, train the personnel for an emergency, liaise with external organizations, verify and update emergency procedures etc..

An onsite preparedness plan should indicate details of in-built safety measures, role of key persons during such emergency situation, measures relating to declaration of emergency, disaster combating procedures, evacuation of non-essential persons, rescue of affected persons, information system, mutual aid, post emergency rehabilitation, long term clean up measures, to keep all concerned abreast of socio-technical requirements.

If the effects of a chemical hazard are not restricted within the plant boundaries and are felt beyond the premises, the situation warrants off-site emergency planning. In such scenarios, the action plan no longer remains in control of the factory management alone, but also becomes a concern for the general public living outside the commuters in the affected zone. To control such a situation, involvement of local and district administration and law and order authorities becomes essential. Therefore, the district magistrates of each district are given the responsibilities of preparation of off-site emergency plan for their districts in command, based on the data submitted by the identified hazardous installation in the area in their on-site emergency plan.

5.2 Objectives of Disaster Management Plan

A major emergency is one, which has the potential to cause serious injury or loss of life. It may cause extensive damage to property and serious disruption, both inside and outside a plant. Sometimes, it requires the assistance of outside emergency services to handle it effectively. Although the emergency may be caused by a number of factors, e.g. plant failure, human error, earthquake, vehicle crash or sabotage, it normally manifests itself in three basic forms, viz. Fire, Explosion or Toxic release.

The purpose of this DMP is to detail organizational responsibilities, actions, reporting requirements and support resources available to ensure effective and timely management of emergencies at, or affecting CEIL's operations associated to production operations in the Rajasthan block. The overall objectives of DMP are to:

- ◆ Ensure safety of people, protect the environment and safeguard commercial considerations
- ◆ Immediate response to emergency scene with effective communication network and organized procedures.
- ◆ Obtain early warning of emergency conditions so as to prevent impact on personnel, assets and environment;
- ◆ Safeguard personnel to prevent injuries or loss of life by protecting personnel from the hazard and evacuating personnel from an installation when necessary
- ◆ Minimise the impact of the event on the installation and the environment, by:
 - Minimizing the hazard as far as possible
 - Minimizing the potential for escalation
 - Containing any release.

This is achieved by:

- ◆ Describing procedures to deal with emergencies affecting personnel, equipment, third party contractors, local communities or the environment
- ◆ Defining the roles and responsibilities of supervisory personnel, (at the Rajasthan site and site-base office) and Emergency Response Group (ERG) and Crisis Response Team (CRT) personnel
- ◆ Describing the external resources available to the ERG for use in an emergency and how these resources will be co-ordinated.

5.3 Scope

The scope of this document is to identify all emergency scenarios, set out the basic principles of emergency response for each of these scenarios, and to present the organization and the arrangements, which are in place for the emergencies.

It is intended to act as an emergency support tool to the standard operating policies of CEIL; it is acknowledged that variations may be necessary subject to the knowledge of supervisory personnel and the particular circumstances of emergency situations as they unfold.

While these procedures would be followed to the greatest possible extent during an incident response, based upon sound management and/or engineering judgement and operational experience variations may be granted by the ERG Leader.

This manual will apply to all emergency situations related to the onshore oil and gas handling and transportation operations associated with the Rajasthan block. This Plan recognizes that the Incident Controller is authorized to initially control and contains any and all emergency situations at the identified Rajasthan field incident site. The Emergency Response Group Leader (ERG Leader) is authorized to control all CEIL emergencies associated to the Rajasthan field operations.

The results of the Risk Assessment (RA) study are used in the preparation of this DMP.

The following hazards as applicable to the wells, pipelines and gas processing facilities in Rajasthan block have been considered in the RA study:

- ◆ Blowouts of wells
- ◆ Oil and gas release due to leaks in the pipelines
- ◆ Leaks in the outlets of oil/gas processing equipment like Separator and Compressor

5.4 Disaster Management Plan: Key Elements

Following are the key elements of Disaster Management Plan:

- ◆ Basis of the plan
- ◆ Accident prevention procedures/measures
- ◆ Accident/emergency response planning procedures
- ◆ Recovery procedure
- ◆ Onsite & offsite crisis management, communication, contact information etc.

5.4.1 Basis of the Plan

Identification and assessment of hazards is crucial for on-site emergency planning and it is therefore necessary to identify what emergencies could arise during processing of gas in the processing terminal and transportation of the gas through pipeline. Hazard analysis or consequence analysis (in case of catastrophic release of hazardous chemicals) is therefore considered as the basis of DMP.

Major hazards/accidents are categorised into the following events involving flammable materials:

- ◆ Hazards from spread of fire, explosion or release of flammable substances from the wells
- ◆ Fire threatening items of pipeline/equipment section containing hazardous / flammable substances
- ◆ Hazards from high levels of thermal radiation for limited duration
- ◆ External interference such as excavation resulting in blow out of wells or large holes or ruptures of the pipeline. Ignition of the released gas/vapour from pipe rupture can cause heat radiation at some distance from the pipeline
- ◆ At sectionalising valve stations, gas/vapour release due to failure of small-bore over-ground pipe work is a credible event. Gas/vapour fires, on ignition of releases, can occur
- ◆ Controlled releases of gas through vents also occur at the sectionalising valve stations during pipeline depressurisation and pigging operations. If such operations are not properly carried out, accidents can occur
- ◆ Risk mitigation measures delineated in Chapter 4 based on consequence analysis also form an integral part of an organised Disaster Management Plan

5.4.2 Accident Prevention Procedures/ Measures

5.4.2.1 General

The American Society of Mechanical Engineers first published the ASME B31.8 code in the US in 1935. It was adopted by the Government's Department of Transportation in the United States as the minimum Federal Standard (192) for Gas Transportation Safety.

ASME B 31.8 as amended by OISD 141 are used as the base design, operation and maintenance code for the system. OISD standard 174 gives the codes for well control. While, OISD standard 189 sets out engineering requirement for the fire fighting equipment for the drilling rigs.

ASME B31.8 (and OISD 141) explicitly requires that each operating company having gas transmission or distribution facilities within the scope of ASME B31.8 shall:

- ◆ Have a written plan covering operating and maintenance procedures in accordance with the scope of code

- ◆ Have a written emergency plan covering facility failure or other emergencies
- ◆ Operate and maintain its facilities in accordance with these plans
- ◆ Modify the plans from time to time as experience dictates and as exposure of the public to the facilities and changes in operating conditions require
- ◆ Provide training to employees in the procedures established for their operating and maintenance functions. The training shall be comprehensive and shall be designed to prepare employees for service in their area of responsibility
- ◆ Keep records to administer the plans and training properly

OISD 141 sets out Engineering requirements necessary for safe design and construction of pressure piping. While it is not a design handbook, it gives basic design principles and formulae. Designs and practices known to be unsafe are prohibited by the code.

A separate plan is provided to deal with situations, which necessitate emergency action. The emergency response plan includes details of the organisational response to emergencies and the safety precautions to be observed in preventing loss of life and damage to property.

Risk mitigation measures based on consequence analysis have also been covered in Chapter 4.

5.4.2.2 Operation & Maintenance

The oil and gas handling system will be fit for purpose after testing and commissioning. Oil and gas industry experiences throughout the world have shown that the main physical dangers a well or a pipeline faces during operation are mechanical damages caused by excavation works adjacent to them and corrosion resulting from breaks in the coating system, which leave the pipe wall steel exposed.

To guard the pipeline against damage, a system of regular surveillance and inspection to warn of mechanical or corrosion damage is employed.

Repairs will have to be made to any mechanical and corrosion damage on the pipeline, which the inspection program discovers. The repairs shall comply with OISD 141 as a minimum.

Following are the main factors, which determine whether the pipeline will stay free of significant defects:

- ◆ Well protection against external interference such as caused by nearby excavations
- ◆ Changes in the well or pipeline environment
- ◆ Adequate well or pipeline markers
- ◆ The effectiveness of the pipeline's corrosion protection
- ◆ The pipeline's protection against external interference such as caused by nearby excavations
- ◆ The influence of ground movement from natural or man-made causes such as settlement geological faults, washouts or mining

Preservation of pipeline integrity in accordance with ASME B31.8 during modification, maintenance and repairs

5.4.2.3 Protecting the Well/Pipeline from External Interference

The pipelines should be laid 100 meters away from the habitated area. In the event of pipeline incident, it may affect the population living in proximity to the pipeline and the environment. An action plan is needed to handle any emergency smoothly with minimum effect on lives and property.

It is essential to protect the wells and pipelines from being struck or damaged by third parties. The primary defence against this occurrence will be:

- ◆ Liaisons with third parties likely to excavate near the wells or pipelines. CEIL shall identify, then make them aware of the well and the gas and oil pipelines and gather advance notifications of their activities
- ◆ Regular patrolling of the wells and pipeline routs to monitor third party activities on the ground. The patrolman should be instructed to report on the following activities taking place in the vicinity of the wells and pipelines :
 - Ground movement
 - Removal of surface soil, tipping or stacking of materials over the wells etc

- Any building or civil engineering works
- Any other activity which may affect wells, pipelines or any other equipment

5.4.2.4 Protecting the Pipeline against Corrosion

To prevent the buried steel pipeline from corroding over time, it should be coated with an electrically insulating coating such as Polyethylene or epoxy. The insulating properties of the coating prevent flow of the very small, naturally occurring electric currents between the pipe and the soil, which cause corrosion of the steel.

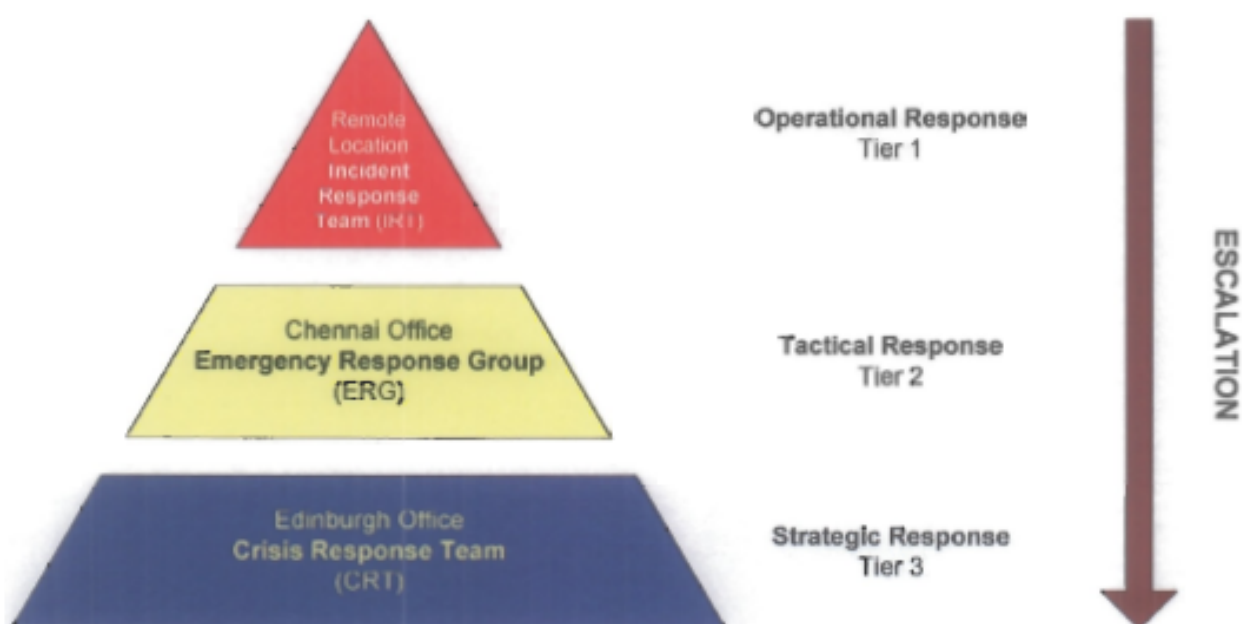
Sacrificial anodes may be placed. This applied current counteracts the induced current flow and will prevent the corrosion of the steel pipe where the coating is damaged or defective. The operation of the corrosion prevention system will be periodically monitored to ensure its effectiveness.

Regular monitoring of the cathodic protection system ensures that it is functioning correctly through the life of the pipeline. Cathodic protection (CP) is a well-established corrosion control process.

There are several techniques, which can be used to determine the condition of the pipeline coating from the ground surface above the pipeline.

5.5 Emergency Management Interface

The following details identify the interface between the Incident Response Team (Site), the Emergency Response Group (ERG) and the Crisis Response Team (CRT).



5.5.1 Incident Response Team (IRT) – Operational Response

It is the Incident Response Team's responsibility to deal with the respective location or asset's incidents / emergencies of minor nature requiring no external assistance and which can be controlled with local resources. For emergencies where external assistance is required the Incident Controller at site must notify Emergency Response Group Leader at Chennai for action.

5.5.2 Emergency Response Group (ERG) – Tactical Response

It is the Emergency Response Group's responsibility to respond and provide assistance to control the response to all major emergencies that occur within the Country (India).

5.5.3 Crisis Response Team (CRT) – Strategic Response

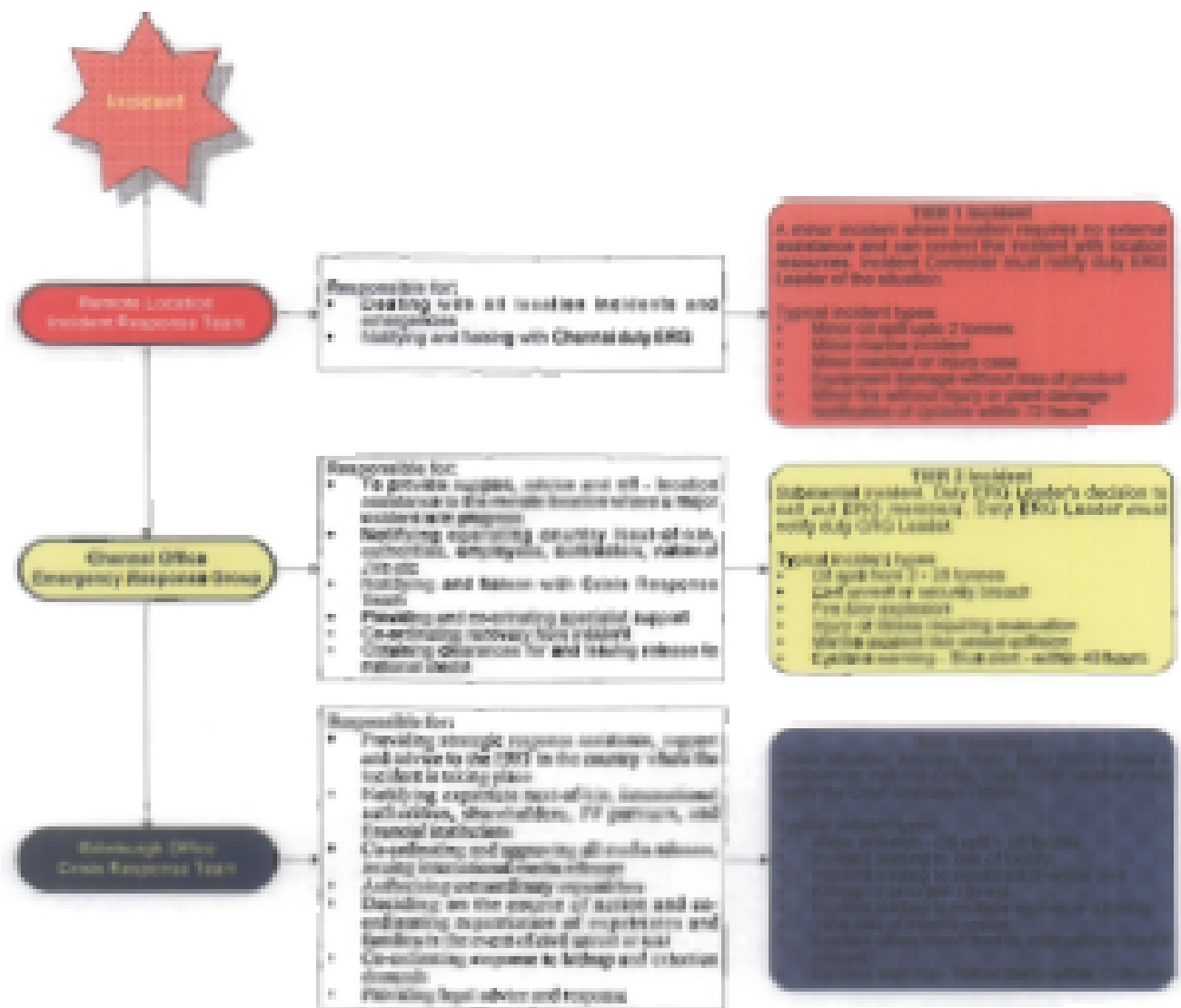
The Crisis Response Team is the key corporate body in Edinburgh, to define and co-ordinate the overall strategic response for major incidents involving any Cairn operations in any Country. A crisis is defined as a situation arising from single or multiple incidents or emergencies that escalate to a point beyond which significant damage to the Company's business could result, including commercial and reputation damage, significant financial loss, shareholder loss of confidence and damages resulting from litigation. When a potential crisis situation appears likely, the CRT will be mobilised to manage issues pertaining to the reputation and the continued commercial well-being of the Company.

The CRT may however also be called upon to address some of the tactical roles that would normally be the responsibility of ERG, for example if the Chennai Office were out of action or in the event of an evacuation from a country, which may equally limit the ERG's capability.

5.5.4 Areas of Interface

The ERG and CRT are committed to the above stated emergency priorities. They will not interfere with the local emergency response unless it is to improve the Company's ability to minimise the corporate effects of the emergency without increasing danger to people or the environment.

Public Affairs, Legal and Financial activities carried out at, for, or on, site are an element of the Emergency Management function and therefore directed in association with the ERG and CRT Leaders.



5.5.5 Emergency Reporting

- When witnessing or receiving notification of an emergency, as much information as possible should be taken and/or conveyed to the relevant emergency activation authority. Where possible, all information should be logged in written form with time and date included and provided to the Incident Controller.
- Personnel working on the field may, at any time, be exposed to an emergency, which could take many forms, for example (but not limited to):

Injuries and/or fatalities	• Exposures
Aggressive releases	• Fires and/or explosions
Equipment hazards	• Impacts
Extreme weather	• Adverse environments

- ◆ When an emergency occurs, an appropriate and prompt response is required, providing precise action to control, correct and return the site to a safe condition. Timely action is also required to protect people, the environment and property from harm.
- ◆ Reporting Forms for actions to be considered, when witnessing an emergency or receiving a report of an emergency.

5.5.6 Within the Field

All near misses and unsafe acts will be written in logbooks / reported in the 'Near miss, unsafe acts, hazards and sub-standard conditions report' and verbally communicated to the concerned Supervisor / Superintendent / Installation Manager at an appropriate opportunity. All accidents and incidents will be immediately reported to the Installation Manager (Incident Controller), and appropriate forms completed.

5.5.7 Field to Emergency Control Centre

All accidents and incidents occurring within the Field facilities will be reported to the Production Manager and Asset HSE Manager as per CEIL Incident Reporting and Investigation Procedure. This includes both situations where there is actual damage to health or equipment and also where there has been a threat of danger or a near miss.

5.5.8 Incident Report

- ◆ One report form covers all accidents / incidents
- ◆ Incident report should be submitted regardless of the severity of the injury, or whether the injured party is a Cairn employee or a contractor
- ◆ Form should be completed and faxed to the Asset HSE Manager and Production Manager for review and distribution.
- ◆ All incident reports are to be followed up with the CEIL investigation report as per the procedure.

5.5.9 Incident Situation Report Form (SITREP)

To be completed and endorsed by the site Incident Controller and faxed to the Emergency Response Group (ERG) at the commencement of any significant incident. The ERG may also fax copies of the SITREP to the CRT Leader as appropriate. The SITREP is continually used to further update the ERG on incident activity.

5.5.10 Medevac Report

- ◆ Completed by the Site Doctor to accompany any person being moved by Medevac
- ◆ Purpose is to provide full information on the patient's condition to the destination hospital.

5.5.11 Internal Distribution

The Asset HSE Manager will distribute copies of reports to all Senior Managers. In the event of a major incident, distribution of various reports (i.e. Incident SITREP / Medevac etc.) will be authorized by the ERG Leader.

5.5.12 Notification to Authorities

The ERG Leader is responsible to ensure that the following agencies are informed of any serious incident:

- ◆ Accident/Damage to Equipment
 - Director General Hydrocarbons, New Delhi
- ◆ Pollution
 - Rajasthan Pollution Control Board, Gandhinagar
 - Ministry of Environment & Forests, New Delhi
- ◆ Installation Manager to advise local District Collector, RDO and Police as appropriate.
- ◆ Contact details for the above agencies included in the contact list.
- ◆ The Asset HSE Manager is responsible to ensure that all reports listed below, and appropriate to the circumstances of an incident, are made to relevant Government agencies. These include:
 - Form IV A - To be completed for each serious occurrence and sent to DGMS within 24 hrs of occurrence of the event
 - Form IV B - To be completed in the event of injury or fatality and sent to DGMS within a week of the occurrence of the incident
 - Form IV C - To be completed within 15 days upon returns to duty of an injured person and sent to DGMS

5.6 Emergency Response Strategies

5.6.1 Introduction

Whenever there is an emergency, the managers/response team is required to swing into action without losing time. Time is the essence of the immediate relief and rescue operations to save human life, to mitigate the impact on the environment and to safeguard commercial consideration. The same is true while dealing with any emergency during the proposed production operations in the Rajasthan block.

This DMP has been prepared keeping in mind the above fact and it is conceptually based on the Trigger Mechanism.

The Trigger Mechanism envisages that on receiving signals of a disaster happening or likely to happen, all activities required for the mitigation process are energised and activated simultaneously without loss of any time. The primary objective of this mechanism is to undertake immediate rescue and relief operations and stabilise the mitigation process as quickly as possible.

The main parameters of such a response plan includes:

- ◆ Signal/Warning Mechanism
- ◆ Activities and their Levels
- ◆ Sub-Activities
- ◆ Command and Control Structure
- ◆ Individual roles and responsibilities of each specified authority to achieve the activation as per response time
- ◆ Response teams for each specified authority
- ◆ Emergency procedures
- ◆ Alternate plans & contingency measures.

5.6.2 Alert Phase

It will be the duty of all site personnel at the site to remain alert at all times for hazardous situations that have the potential to escalate into an emergency incident. All the members of the ERG and CRT will be on a standby and will be activated as required. All members of the response will be familiar with the CEIL Disaster Management Plan.

Emergencies on site can be initiated in a number of ways depending upon the severity of the incident by the site fire alarm siren which any personnel in the field can activate. The site siren will sound in an intermittent mode. Also, the individual fire alarms will sound in the area of the incident.

This procedure initiates the Site Fire and Rescue Department and Site Security into their standard procedures and the Site Fire and Rescue Department to attend the incident. This has the advantage of permitting the earliest possible action to be taken to control the immediate situation, which may avoid the development of a major emergency.

The Incident Controller will attend the scene of the incident and the ERG Leader will be notified. Depending upon the severity of the emergency (Tier 2), the ERG Leader will activate the ERG and notify the CRT Leader as appropriate. Only if it's a major disaster (Tier 3), the CRT will be activated. The Incident Controller will assess the situation from the edge of the incident scene to reduce the probability of personal injury. The Emergency Support Team members will be on standby ready to go to the Emergency Control Centre.

Evacuation of employees to the nearest assembly point or refuge may be required, if not hindered by fire.

5.6.3 Declaration of Emergency

To enable the appropriate level of response to be implemented, emergency incidents are to be categorized according to three levels as follows:

Tier 1

- ◆ The incident can be effectively and safely managed, and contained within the facility by operations staff
- ◆ The incident has no effect outside the site.
- ◆ There is unlikely to be serious danger to life, the environment or to company assets or reputation.

Tier 2

- ◆ The incident cannot be effectively and safely managed and contained at the installation or facility by operational staff and some form of additional assistance is required

- ◆ The incident may be “on site”, have some effect beyond the “site” and an external emergency services will be involved
- ◆ There is likely to be danger to life, to the environment or to company assets or reputation.

Tier 3

- ◆ The incident has ESCALATED to a level where it begins, or has the potential to begin, to adversely affect the Company, its Joint Venture Partners, or the public on a broad front
- ◆ The incident will have technical, press, public affairs and personnel implications, which require immediate assistance
- ◆ There will be one or combination of the following:
 - ◆ Death and/or serious injury
 - ◆ Potential for significant pollution or environment damage
 - ◆ Substantial damage or property

Emergencies will initially be under the control of the Incident Controller whose main tasks are to locate the source and nature of the incident, to inform the ERG Leader, and activate the Site Security and Emergency Services.

During normal working hours the Incident Controller will keep the ERG Leader informed and jointly decide whether it's a Tier 1, Tier 2 or Tier 3 emergency. For a major emergency appropriate Emergency Control Centres will be set up, the site Emergency Support Team summoned and the ERG and CRT activated as required.

5.6.4 Emergency Alarm (Siren)

Personnel on site will know that a Major Emergency has been declared, if the site fire alarm siren and all local fire alarm systems are activated. The Emergency Siren Modes will be operated as per internationally accepted alarm codes.

5.6.5 Preparation for Emergencies**5.6.5.1 Command by Competent Persons**

Effective command and control starts with a clear definition of the overall command and control structure, and description of the duties of key personnel with specific responsibilities for emergency response.

5.6.5.2 Number of Persons for Emergency Duties

The command/control of emergencies must identify the minimum number of persons required to provide an adequate response to emergencies. This includes having staffed trained and competent to fulfil the roles of other members of staff if they are not available.

5.6.5.3 List of Persons for Emergency Duties

A list of the staff in the field having emergency duties is displayed in the Control Room. It is the responsibility of the Incident Controller to ensure that these lists are kept up to date.

5.6.5.4 Control of Emergencies

The major systems for controlling emergencies and preventing escalation are detailed in this DMP, which gives the emergency procedures to be followed in case of an impending / occurring disaster. It should be noted that during any emergency during the production operation in the Rajasthan block, this document would be referred. This would result in the most efficient emergency response strategy to combat the impending/occurring disaster.

5.6.5.5 Assembly Procedures

When personnel arrive on site, they are assigned to an assembly station.

Assembly Areas

- ◆ Non-essential personnel assemble within the accommodation
- ◆ Fire Team at the Alert Team Station
- ◆ Emergency Response Team in the office of Incident Controller.

Lists

Assembly lists should be kept up to date and are produced by a senior person. Copies are displayed at each Assembly Station.

Accounting for Personnel

The person in charge at each Assembly Station checks the personnel according to the assembly list and relays the information to the site HSE Support and the Incident Controller. The HSE Support person conducts the final headcount and notifies the Incident Controller of the results and discrepancies if any.

Co-ordination

The Senior person in the Control Room is charged with co-ordinating the information/response measures from the various Assembly Stations and ensuring that all personnel are accounted for. He must refer to the HSE Support or the Incident Controller if any personnel are not accounted for or if there are impediments to carry out the response strategy.

5.6.6 Post Emergency

The post emergency phase is an important event in the long-term emergency response strategy for CEIL.

It is absolutely necessary for the Emergency Response Team (ERT) members (IRT, ERG and CRT) to review the ERP and the incident response events and provide their inputs for response improvements or ERP updates. All personnel involved in the emergency response actions during an incident will be debriefed by their superior officer.

It will be the responsibility of the designated ERT members to prepare a complete incident report collating incident reports/logs from the respondents and forward the same to higher authorities as appropriate or send notifications to the Government authorities as the case may be. It will be the responsibility of the ERG leader to develop a post emergency action plan with the assistance of Incident Controller.

5.7 Emergency Response Organisation**5.7.1 Incident Response**

The Incident Controller (IC) is responsible for co-ordinating the on-site tactical response to any emergencies arising out of the operations in the facility and will activate and direct emergency response personnel as appropriate to the emergency. The Incident Controller will notify and correspond with the ERG Leader.

If required, the following personnel or teams are available to be activated at the site:

Incident Controller	HSE Support
Site Medical Centre	Site Contractor Mgt. (as appropriate)
Fire Team Leader	Technical Support
Control Room	Scribe

5.7.2 Emergency Response Group

The Emergency Response Group (ERG) is responsible for co-ordinating the strategic response relative to any Tier 2 emergency arising out of the production activities in the facility. The ERG is activated and directed by the ERG Leader, and will assemble in the Emergency Coordination Centre (ECC).

If additional support is required for the CEIL response, the following personnel should be mobilized as required:

Operation & Technical Co-ordinator	QHSE Co-ordinator
Human Resources & Services Co-ordinator	Public Affairs Co-ordinator
Logistics Co-ordinator	Recorder
Security Co-ordinator	Reception Co-ordinator
Telecommunication Co-ordinator	

5.7.3 Crisis Response Team

The Crisis Response Team (CRT) is responsible for co-ordinating the overall strategic response to any Tier 3 emergency arising out of any activity in the country. The CRT is activated and directed by the Crisis Response Team Leader (CRT Leader).

The CRT will initially assemble in the designated Emergency Management Centre (EMC) and will be directed by the CRT Leader, or alternate.

If an incident requires additional support, the following personnel should be mobilized:

Finance and Commercial Co-ordinator	Operations / Technical Co-ordinator
Risk, Health, Safety and Environment Co-ordinator	Public Affairs Co-ordinator
Human Resources and Services Co-ordinator	Legal and Joint Venture Partner Co-ordinator
Recorder	

5.7.4 Incident Site Roles and Responsibilities

The roles and responsibilities of the members of the Incident Response Team are outlined below:

5.7.4.1 HSE Engineer**Pre-emergency**

Maintain familiarization with Field Emergency Response Plan, key respondents and appropriate emergency notification requirements.

During Emergency

- ◆ Liase with Incident Controller for incident briefing and likely requirements
- ◆ Assist Incident Controller in co-ordination of emergency response personnel as appropriate
- ◆ Liase with the site doctor for emergency medical/first aid as appropriate
- ◆ Co-ordinate support in areas of administration and information gathering
- ◆ Brief personnel regarding likely incident needs and safe working practices, monitor them for signs of trauma, fatigue and stress
- ◆ Continually refer to ERP procedures, role checklists and OSCP, use Emergency Response Log
- ◆ Filter flow of information and keep Incident Controller informed of situation
- ◆ Prepare/maintain supporting information flow between Incident Controller and ERG Leader

For Evacuation

- ◆ Ensure headcount of personnel at Fire station Muster Point and Main Gate (including Fire Teams) etc
- ◆ Ensure third party contractors, security personnel, transport drivers and cartage contractors are included in all headcount
- ◆ Check headcount results; notify Incident Controller of results and any discrepancies
- ◆ Follow Evacuation procedure

For HSE Incident

- ◆ Notify ERG HSE Co-ordinator of any likely HSE effects of incident on nearby environments and/or communities

- ◆ Liase with ERG HSE Co-ordinator for incident updates and likely requirements
- ◆ Consider need for relief of personnel in your charge
- ◆ Consider relief/support for your role; prepare hand-over reports and plans
- ◆ As time permits, maintain log of events for collection at end of incident; provide to Incident Controller

Post- Emergency

- ◆ Debrief personnel in your charge before releasing them from duty
- ◆ Review incident response events; provide recommendations for response improvements or ERP updates
- ◆ At the conclusion of any incident/emergency, prepare a complete incident report; provide to Incident Controller

Primary Role : To provide and co-ordinate support to responses designed to mitigate the impact of the incident and ensure efficient information flow between site and ERG.

5.7.4.2 Sr. Administration Officer

Pre-emergency

- ◆ Maintain familiarization with Field Emergency Response Plan, key respondents and appropriate emergency notification requirements
- ◆ Establish/maintain “goodwill” contact with all relevant community groups, their key contact persons and any relevant groups

Emergency Actions

- ◆ Liase with HSE Engineer for incident briefing and likely requirements; maintain liaison
- ◆ Continually refer to ERP procedures and role checklists; use Emergency Response Log
- ◆ Brief personnel in your charge regarding likely incident needs and safe working practices, monitor them for signs of trauma, fatigue and stress

- ◆ Prepare an initial community impact assessment; provide to HSE Engineer
- ◆ Ensure community near incident site (residents, farmers etc.) are advised and regularly updated of incident status and any likely impact if applicable
- ◆ Assess requirement for post trauma counseling for affected site/community members
- ◆ Ensure Incident Controller is kept updated through HSE Engineer with all community liaison and media issues; maintain liaison as appropriate

For Remote Spokesperson Role (This role needs to be carried out only on confirmation with ERG Leader and Incident Controller).

- ◆ Liase with Company Public Affairs Co-ordinator for media strategy and likely requirements
- ◆ Consult with ERG leader for most current incident information
- ◆ Review media conference material with ERG PA and Public Affairs Co-ordinator
- ◆ Rehearse with Public Affairs Co-ordinator before media conference / interview / release
- ◆ Ensure visual conference aid material (charts, maps, plans etc.) and relevant technical support personnel are available
- ◆ Assess effectiveness of each media conference with Public Affairs Co-ordinator
- ◆ Regular updating of ERG PA and Public Affairs Co-ordinator of all key media events
- ◆ Consider meeting with relevant community leaders/groups
- ◆ Consider need for relief of personnel
- ◆ Prepare hand-over reports and plans
- ◆ Maintain log of events for collection at end of incident; provide to Incident Controller

Post-emergency

- ◆ Debrief personnel in your charge before releasing them from duty
- ◆ Review incident response events; provide recommendations for response improvements or ERP updates
- ◆ At the conclusion of any incident/emergency, prepare a complete incident report; provide to Incident Controller

Primary Role : To provide a link between Cairn and immediate community and to effectively assess the impact and implement appropriate responses and actions; to act as Remote Spokesperson, if asked to act in this role.

5.7.4.3 PIC-onshore**Pre-emergency**

Maintain familiarization with Field Emergency Response Plan, key respondents and appropriate emergency notification requirements

Emergency Actions

- ◆ PIC - Onshore is Cairn representative assuming control and liaison activities at an actual incident site (this role may be assumed by first person on the scene and then assumed by a more appropriate or senior Cairn person as an incident escalates)
- ◆ If not the first person at the scene, obtain all relevant incident information from person who raised the alarm or who initially assumed the role of PIC - Onshore
- ◆ Make early contact and maintain liaison with the Production Superintendent as emergency requires
- ◆ Evaluate and initiate immediate action to mitigate the effect of the emergency and request any additional resources likely to be required
- ◆ Assess the likely impact of incident to simultaneous operations, the local community or the environment
- ◆ Continually update Production Superintendent with ongoing incident response activities and requirements

- ◆ Advice Production Superintendent of any processes or systems that are threatened, should be diverted or that should be closed etc.
- ◆ Brief personnel in your charge and constantly monitor them for safe working practices, stress, fatigue or trauma

For Fire and / or Explosion

- ◆ Immediately confirm location, extent and type of fire
- ◆ Confirm all personnel in the immediate area
- ◆ Assess likely cause of fire/explosion and undertake corrective action/damage control measures
- ◆ Provide incident information to Fire Chief
- ◆ Guide fire teams to incident site by safest route as required
- ◆ Monitor events; determine need for evacuation of personnel / equipment if situation warrants
- ◆ Consider need for relief of personnel in your charge
- ◆ Consider relief/support for your role; prepare hand-over reports and plans
- ◆ As time permits, maintain log of events for collection at end of incident; provide to Incident Controller

Post-emergency

- ◆ Debrief personnel in your charge before releasing them from duty
- ◆ Review incident response events; provide recommendations for response improvements or ERP updates
- ◆ At the conclusion of any incident/emergency, prepare a complete incident report; provide to Incident Controller

5.7.4.4 Site Doctor

Pre-emergency

Maintain familiarization with Field Emergency Response Plan, key respondents and appropriate emergency notification requirements.

Emergency Actions

- ◆ Liase with HSE Engineer for likely medical needs and requirements
- ◆ Consider the need to mobilise Medical Response Team (Trained First Aides)
- ◆ Prepare appropriate Medical Report to be sent along with patient
- ◆ Liase with concerned hospitals for necessary treatment (follow up)
- ◆ Provide appropriate medical advice to the concerned

Post-emergency

- ◆ Review incident response events; provide recommendations for response improvements or ERP updates
- ◆ At the conclusion of any incident/emergency, prepare a complete incident report; provide to Incident Controller
- ◆ Follow-up periodically on the recovery of the patient/medical treatment rendered

5.7.4.5 Fire Chief

Pre-emergency

- ◆ Maintain familiarization with Field Emergency Response Plan, key respondents and appropriate emergency notification requirements
- ◆ Establish / maintain “goodwill” contact with all relevant local response agencies, their key personnel and the respective notification/call-out requirements

Emergency Actions

- ◆ Liase with Maintenance Superintendent for incident briefing and likely requirements, confirm nature, extent and location of emergency; maintain liaison
- ◆ Organise Fire Team from available, trained personnel assembled at muster point; ensure HSE Engineer receives list of Emergency Response Team member's names (for headcount purposes)
- ◆ Proceed to incident site; develop and implement response strategy with Maintenance Superintendent and PIC-Onshore

- ◆ Continually assess situation and requirements for fire fighting materials and equipment
- ◆ Under direction of Maintenance Superintendent, conduct SAR if required, for missing personnel
- ◆ If incident (e.g. fire) is assessed as uncontrollable, inform Incident Controller and move back to Fire station muster point; liase with Incident Controller and await instructions

Post-emergency

- ◆ Debrief personnel in your charge before releasing them from duty
- ◆ Review incident response events; provide recommendations for response improvements or ERP updates
- ◆ At the conclusion of any incident/emergency, prepare a complete incident report; provide to Incident Controller

5.7.4.6 Production Superintendent

Pre-emergency

- ◆ Maintain familiarization with Emergency Response Plan, key respondents and appropriate emergency notification requirements
- ◆ Establish resource database of all relevant technical organizations, who are likely to be required for site incidents
- ◆ Maintain familiarization with the technical organizations key personnel and respective notification/call-out requirements

Emergency Actions

- ◆ When activated, liase with Incident Controller for incident briefing and likely requirements, maintain liaison
- ◆ Continually refer to ERP procedures and role checklists; use Emergency Response Log
- ◆ Brief personnel regarding likely incident needs and safe working practices, monitor them for signs of trauma, fatigue and stress

- ◆ Assume responsibility for gathering technical information required for response strategies and technical assessment of incident; source engineering drawings, plans etc. as required
- ◆ Constantly monitor effectiveness of technical response strategy
- ◆ With ERG, consider forward planning issues; be pro-active in considering technical data needs etc.
- ◆ Arrange for safety induction of technical support contractors as appropriate
- ◆ Support ERG regarding technical issues that may be required by PA
- ◆ Consider need for relief of personnel
- ◆ Continually monitor/adapt requirement plans to suit escalation or reduction of incident needs

Post-emergency

- ◆ Review incident response events; provide recommendations for response improvements or ERP updates
- ◆ At the conclusion of any incident/emergency, prepare a complete incident report; provide to Incident Controller

5.7.4.7 Maintenance Superintendent

Pre-emergency

- ◆ Maintain familiarization with Field Emergency Response Plan, key respondents and appropriate emergency notification requirements
- ◆ Establish resource database of all relevant technical organizations, who are likely to be required for site incidents
- ◆ Maintain familiarization with the technical organizations key personnel and respective notification/call-out requirements

Emergency Actions

- ◆ Co-ordinate with Fire Chief to direct Emergency Response Team
- ◆ When activated, liaise with Incident Controller for incident briefing and likely requirements; maintain liaison

- ◆ Liase with Electrical/Mechanical/Instrumentation in charges and instruct appropriate actions relevant to their functions
- ◆ Co-ordinate through CEIL project engineer for handling controls related emergency
- ◆ Continually refer to ERP procedures and role checklists; use Emergency Response Log
- ◆ Brief personnel regarding likely incident needs and safe working practices, monitor them for signs of trauma, fatigue and stress
- ◆ Consider need for relief of personnel

Post-emergency

- ◆ Review incident response events; provide recommendations for response improvements or ERP updates
- ◆ At the conclusion of any incident/emergency, prepare a complete incident report; provide to Incident Controller

Primary Role - To organize, direct & guide Emergency Response Team including site doctor for initial incident response & liase concerned department in charge for suitable emergency response.

5.7.4.8 Scribe

Pre-emergency

Maintain familiarisation with Field Emergency Response Plan, key respondents and appropriate emergency notification requirements

Emergency Actions

- ◆ Liase with Incident Controller for incident briefing and likely requirements
- ◆ Ensure that site Incident Control Centre (ICC) is set-up and all appropriate emergency procedures, site plans etc. are available; have copies of the Contact Directory available and displayed
- ◆ Check that ICC communications equipment is working; verify with Site Radio Operator that all Radio Room communications systems are functioning and available

- ◆ Make early contact with ERG leader, maintain liaison as/when required
- ◆ Continually refer to ERP procedures and role checklists; use Emergency Response Log
- ◆ Co-ordinate display of known information on ICC wall charts
- ◆ Set up incident filing system
- ◆ Obtain copy of results of head counts from Incident Controller
- ◆ Maintain accurate master chronological log of activities and circumstances, record and file all information received from incident locations into incident filing system
- ◆ Ensure the incident information board(s) is accurate and kept updated
- ◆ Co-ordinate support in areas of administration and information gathering
- ◆ Filter flow of information and keep Incident Controller informed of any situation changes
- ◆ Forward completed incident SITREP, validated by Incident Controller, to ERG
- ◆ Prepare and maintain supporting information flow between Incident Controller and ERG Leader
- ◆ Consider relief/support for your role; prepare hand-over reports and plans

Post-emergency

- ◆ Review incident response, including any logs of events collected; provide recommendations for response improvements or ERP updates
- ◆ At the conclusion of any incident, prepare a complete incident report; provide to Incident Controller

5.7.4.9 Person Taking Calls

Emergency Actions

- ◆ Ensure all calls are taken away from site Incident Control Centre
- ◆ For emergency calls, put the caller through to Incident Controller (or Alternate) or take a message for a return call

- ◆ If relatives call, refer them to the Incident Controller until a “Relatives Response” dedicated number is established
- ◆ If level of incoming calls becomes too great, contact HSE Engineer for additional resources
- ◆ Consider relief for your position for an extended incident response
- ◆ As time permits, maintain log of events for collection at end of incident; provide to Incident Controller

Post-emergency

- ◆ Pass “return call” requests to relevant persons for action
- ◆ Contribute to incident debrief
- ◆ Review incident response events; provide recommendations for response improvements or ERP updates
- ◆ At the conclusion of any incident/emergency, prepare a complete incident report; provide to Incident Controller

Primary Role - To filter incoming telephone calls, ensuring Incident Controller receives only relevant emergency calls while ensuring all other calls are handled appropriately.

5.7.4.10 Control Room Operator

Pre-emergency

Maintain familiarization with Field Emergency Response Plan, Key respondents and appropriate emergency notification requirements.

Emergency Actions

- ◆ Identify the caller and confirm the emergency.
- ◆ Get a description of exactly what has happened, confirm details such as
- ◆ When, where, nearest location etc., as appropriate.
- ◆ What risks continue to exist
- ◆ What action has been initiated

- ◆ Ascertain whether any medical assistance is required at the accident scene.
- ◆ Activate the Emergency Siren
- ◆ Notify Production Superintendent
- ◆ Start the main firewater pump immediately on remote if required
- ◆ Verify the incident details, escalation potential and actions already initiated
- ◆ Act according to the instructions from Production Superintendent
- ◆ Log all the events and actions.
- ◆ Consider relief / support for your role if required
- ◆ Prepare hand-over /status report if required.

5.8 Emergency Response Action

5.8.1 Emergency Response Centres

5.8.1.1 Incident Control Centre (ICC)

The Incident Controller would set up the incident control centre. It is suggested that best location for incident control centre is the main control room. There will be radio, telephone or messenger contact with the Emergency Control Centre.

The incident area will be taped off and warning notices posted. The in-house Fire Team will cordon off the incident area (Inner Cordon). Route markings from Emergency Control Centre to the incident to aid the emergency services will be arranged.

5.8.1.2 Emergency Control Centre (ECC)

The Emergency Control Centre is to be set up at the oil and gas processing facility. The centre is equipped to receive and transmit information and directions from and to the Incident Controller as well from outside. ECC shall contain equipment for logging the development of the incident to assist the controllers to determine any necessary action.

The Emergency Control Centre should contain:

- a) Adequate number of external telephones. At least one will be ex-directory or capable of use for outgoing calls only. This will avoid the telephone switchboard being overloaded with calls from anxious relatives, the press etc.;
- b) Adequate number of internal telephones;

- c) Radio equipment;
- d) Plans of the works to show:
 - ◆ Areas where there are large inventories of hazardous materials, including oil storage
 - ◆ Sources of safety equipment
 - ◆ The fire-water system and additional sources of water
 - ◆ Stocks of other fire extinguishing materials
 - ◆ Assembly points, casualty treatment centres
 - ◆ Location of the works in relation to the surrounding community and
 - ◆ Lorry parks
 - ◆ Additional plans which may be marked up during the emergency to show:
 - ◆ Areas affected or endangered;
 - ◆ Deployment of emergency vehicles and personnel;
 - ◆ Areas where particular problems arise;
 - ◆ Area evacuated; and
 - ◆ Other relevant information.
- f) HAZCHEM sheets for the various hazardous materials used on-site
- g) Note-pads, pens, pencils to record all messages received and sent by whatever means;
- h) Nominal roll of employees or access to this information;
- i) List of key personnel, addresses and telephone numbers.

Emergency Control Centre is located, designed and equipped to remain operational in an emergency.

5.9 Accident / Emergency Response Procedures

In order to deal with an emergency, a complete emergency procedure document will be prepared which identifies the key personnel involved with their specific duties and responsibilities.

This emergency plan will include all requirements for dealing with such a situation, so that all the equipments and personnel can be mobilised in the shortest possible time.

Basic Features

In the development of emergency procedures, following factors should be kept in view :

- ◆ Identification of situations i.e. what can happen and how it can happen
- ◆ Identification of problem/ priority areas i.e. where it can happen
- ◆ Identification of individuals i.e. who is to take action
- ◆ Duties of individuals.
- ◆ System or equipment to be used and when to use it.
- ◆ Procedures for operating the system or equipment

Basic Actions

The basic actions required to handle any emergency are as follows:

- ◆ Operation of emergency shut down systems
- ◆ Maintenance of telephonic communication
- ◆ Persons to be nominated for evacuation
- ◆ Effective internal communication by public address system and walkie-talkie sets

The organizational chart identifying personnel who are to co-ordinate an emergency with assigned responsibilities and specific functions, is to be formulated for the Facility in an integrated manner as given in **Fig. 5.1**. Communication links will be established with local authorities such as factory/section inspector, police station, fire brigade, hospital etc., State and Central authorities to meet the challenges of emergencies and ensure reliability of functioning of the communication system. Adequacy and efficiency of fire fighting and fire detection equipment, personal protective measures, medical services, safety and emergency training will be ensured.

The purpose of this section is to provide “all Hazards” emergency response procedures to previously identified hazards and threats to CEIL areas of operation and activities in the Rajasthan block.

5.9.1 Blowout

5.9.1.1 Person Discovering Blowout

- ◆ Person on the spot should do the following in case the kick is timely detected:

In case of string at the bottom of hole

- ◆ Lift and clear tool joint out of rotary and stop pumps
- ◆ Close BOP and choke
- ◆ Record shut in drill pipe pressure(SIDP) and shut in casing pressure(SICP)
- ◆ Prepare kill sheet and make calculations for standard well killing procedure.

In case of while making trip

- ◆ Stop tripping operations
- ◆ Position tool joint at rotary table and set slips
- ◆ Install safety valve and close safety valve
- ◆ Open choke line
- ◆ Close BOP and choke
- ◆ Record shut in SIDP and SICP
- ◆ Prepare the kill sheet and make calculations for standard well killing procedure

In case of string out of the well

- ◆ If well condition permits attempt – run in hole and whenever situation is critical shut the well by following the steps as mentioned in case of while making trip.
- ◆ If the trip in is not possible then use volumetric method of well control.

In case of sudden kick

- ◆ Close the BOP.
- ◆ Record SIDC & SICP.
- ◆ Prepare kill sheet and make calculations for standard well killing procedure.
- ◆ On detection of a kick, the Senior Toolpusher/ Supervisor is to be informed immediately

5.9.1.2 Supervisor / PIC

- ◆ Supervisor to minimise ignition sources
- ◆ Senior Tool pusher and Supervisor are to assess the situation and declare the incident to be:
 - ◆ Minor event, which can be brought under control using in-situ equipment
 - ◆ Serious event, which in the opinion of the Supervisor, may not be brought under control
 - ◆ Major event, in which the well is unlikely to be brought under control
- ◆ Incident Controller to be informed immediately if the event is classified as serious or major event
- ◆ Instruct site control room to suspend production operations.

5.9.1.3 Incident Controller

- ◆ Incident Controller to inform the ERG Leader, provide full details and likely requirements and maintain contact
- ◆ Activate site response personnel as appropriate; provide full incident briefing and likely requirements; maintain liaison
- ◆ Ensure Fire team is on standby
- ◆ Incident Controller to instruct all non-essential personnel to prepare for evacuation. In a major emergency, an order for total evacuation must be given
- ◆ After situation has returned to normal, inspect incident site to determine whether further corrective action is required to make situation safe.

5.9.1.4 ERG Leader

- ◆ Obtain full incident briefing and likely requirements from Incident Controller; maintain liaison
- ◆ Activate ERG as appropriate
- ◆ Notify CRT Leader; provide full incident briefing and likely requirements

- ◆ Co-ordinate support activities as required
- ◆ Determine need for external assistance for safety of personnel, well control and pollution prevention

5.9.1.5 All Response Members

Maintain log of events for collection at the end of the incident.

5.9.2 Fire / Explosion (General)

The following actions would be taken in case of the above emergency:

- ◆ Person first on the scene
- ◆ Rescue any personnel in danger (do not endanger yourself)
- ◆ Raise Alarm and evacuate the work area.
- ◆ Contain fire, close doors/windows to contain the fire
- ◆ Extinguish fire only if it is safe and you are trained to do so

General

- ◆ If fire is small and respondent is trained to do so, use nearest fire extinguisher and attempt to fight the fire/extinguish the source while calling for assistance
- ◆ If fire escalates or is bigger than first anticipated, immediately raise the alarm ensuring all contractor and CEIL personnel are informed
- ◆ Mobilize Fire Team if available
- ◆ Ensure the safety of all personnel when responding to the incident
- ◆ Request assistance from emergency services if available
- ◆ Confirm location, extent and type of fire/explosion and where possible eliminate the source
- ◆ Shut down and isolate electrical supply to affected area if safe to do so
- ◆ Consider suspension of operations and take actions to secure area
- ◆ Check for any exposures that are likely to escalate the incident (fuel drums, chemicals, oxy-acetylene bottles, petrol, kerosene, gas bottles, tyres etc.)

- ◆ If gas fire, do not try to extinguish unless gas flow can be turned off immediately. if gas cannot be turned off, concentrate on stopping spread of fire and cooling activities (e.g. cooling exposed vessels etc)
- ◆ Evacuate any personnel at risk to a safe distance upwind from the incident area and wait until advised otherwise
- ◆ When rescuing personnel in danger, ensure own escape route first; do not endanger yourself by entering an area containing smoke and/or noxious fumes
- ◆ Confirm all personnel are accounted for
- ◆ Monitor events and determine need for full evacuation of personnel/equipment
- ◆ Activate damage control procedures.

5.10 Procedures for dealing with Reported Gas/ Vapour Escapes

CEIL is responsible for the organisation and assignment of responsibility for:

- ◆ The setting up of a continuously manned Emergency Control Centre for the receipt of telephone calls related to emergencies and gas/ vapour escapes and/or from which, the employees are directed by telephone and/or radio
- ◆ The provision of adequate management, co-ordination and supervision of all administration and operations necessary to maintain disciplined progress and clearance of emergency work
- ◆ The organisation of adequate staff and other resources in order to progress reported gas/vapour escapes within the specified times
- ◆ The organisation of facilities for the monitoring of the receipt, issue, attendance at and clearance of emergency work so as to ensure that none are overlooked or unduly delayed

5.11 Fire Prevention Planning and Measures

Fire is one of the major hazards, related to natural gas and crude oil pipeline (ref. Chapter 3). Fire prevention and code enforcement is the area of responsibility of the fire service.

Safe operating practices reduce the probability of an accident fire in the facility. Personnel should understand their duties and responsibilities and be attentive to conditions that might lead to fire. Following procedures are recommended:

- ◆ There should be provision for safe handling and storage of dirty rags, trash and waste oil. Flammable liquids and chemicals if spilled, should be immediately cleaned
- ◆ Containers of paints and hydrocarbon samples, gas cylinders for welding and cutting should be stored properly
- ◆ Cutting and welding operations should be conducted in accordance with safe procedures
- ◆ “No Smoking” areas should be clearly identified by warning signs
- ◆ Equipments should be maintained in good operating conditions and kept free from external accumulation of hydrocarbons. Particular attention should be given to crude oil pump, seals, diesel and gas engines which could be potential source of ignition in the event of a failure

The Disaster Management Plan will address the issue of a fire event and the procedure to be adopted in the very unlikely event of this occurring.

If a fire starts in any well or a pipeline section, that section of pipeline will be immediately isolated by closing the section (block) valves, as quickly as possible. Surrounding facilities will be cooled with water. The Public will be advised to move away from the fire and seek shelter to avoid exposure to heat radiation.

5.12 Communication

An essential component of a DMP is the Communication Links necessary for gathering information needed for overall co-ordination. Emergency Control Centre links with incident scene and with in-house as well as outside emergency services is necessary. Too much dependence on the Public Telephone system is insufficient, as it can soon be overloaded in an emergency situation. A multi-user wireless paging system with selective call facility is also useful for promptly locating key operating personnel in the plant, both during normal conditions and during emergencies. A public address (PA) system with loud speaker installed at vital installations can be extremely useful during emergencies. An

additional location and transit communications can be addressed by using vehicle and well site installed VHF units.

5.13 Emergency Control Centre

The establishment of a 'focal point' or 'EMERGENCY CONTROL CENTRE' to co-ordinate emergency response activities within a relevant area is essential.

The emergency control centre will be sited in an area of minimum risk (Operational Control Room of the Gas Processing Station) and will have easy and fast access to all major hazardous installations.

Emergency control centres will be equipped with the following:

- ◆ An adequate number of external telephones
- ◆ An adequate number of internal telephones (if required)
- ◆ Wireless communication system with adequate number of portable handsets
- ◆ Notepads, pens & pencils
- ◆ A list of external agencies likes Fire Brigade, Police, Hospitals, Port, neighbouring Industries, Telephone co. etc.
- ◆ Drawing of the Terminal and Pipeline network
- ◆ Source of safety and fire equipment
- ◆ List and location of 'LEAK' clamps
- ◆ A nominal role of employees
- ◆ First-aid kits
- ◆ A list of KEY PERSONNEL with addresses, telephone numbers, etc. with their roles and responsibilities

5.14 Recovery Procedure

Following an accident on the well, pipeline or equipment, there shall be a full recovery procedure as part of the Disaster Management Plan. The recovery procedure shall deal with two distinct situations described below.

5.14.1 Pressure Reduction in Pipeline or Flow Restriction

The Operations Manager may have to restrict the pressure or reduce the flow in the pipeline, depending on the severity of the accident. Following the required repair or attention to any safety detail, the pipeline should be brought back into full service by manually attending the appropriate valves, along with full communication with the Control Engineer at the control station. When full operating conditions are established, any barriers or excavations should be removed and the incident site should be returned to its original condition. All members of the emergency response team should be kept in full contact throughout this exercise and should be informed when the pipeline gas flow/pressure situation is back to normal.

5.14.2 Complete Shut-down of Pipeline

This would occur if the pipeline suffers a rupture from third party interference and gas escapes. At such instance, repair of the pipeline is necessary and a new section of pipeline is needed to be installed to replace the damaged section. For minor leaks, it may be acceptable to install a repair clamp and the Operations Manager will assess this. When any non-destructive testing requirements are completed on welds or repairs, then the pipeline anti-corrosion wrapping must be made properly. The excavations need to be reinstated and the pipeline can be brought back to service as documented in the appropriate maintenance manual. All members of the emergency response team should be kept informed at every stage of the operation.

5.15 Disaster Management Plan: Onsite Crisis

Identification of Personnel and Assessment of Responsibilities on specific functions of Co-ordinating Authority.

In order to effectively deal with emergencies, the organisational chart for on-site emergencies (**Fig. 5.1**) should be periodically reviewed and updated. Usually, for Oil and Gas facilities, following co-ordinators are required to co-ordinate for various activities during the emergency:

Incident Controller (IC)	:	Installation Manager
Operations Co-ordinator (IC)	:	Production Manager
Fire Fighting & Safety Co-ordinator	:	Fire & Safety Incharge
Medical Incharge	:	Medical Officer / Paramedic

Communications Co-ordinator	:	Electrical/Instrumentation Incharge
Services Co-ordinator	:	Maintenance Incharge
Logistics Co-ordinator	:	Administrative Incharge

5.15.1 Role of Incident Controller

He shall be the main guiding force in directing the emergency operations and will be in charge of overall control of the disaster. The actions include:

- ◆ On hearing the fire siren or on receiving information about the disaster, he will immediately take charge of the emergency control centre
- ◆ To declare the category of the emergency after discussing with other team members
- ◆ To instruct all the team members/ co-ordinators to make necessary arrangements
- ◆ To inform mutual aid partners about the disaster
- ◆ Instruct the safe shut down of system in consultation with emergency site incharge and key personnel
- ◆ If necessary, arrange for evacuation of population in the neighbouring villages
- ◆ Carry out search for casualties within the affected area and arrange for first aid/hospitalisation of victims, if required
- ◆ Ensure not to operate the plant/system unless it is declared safe by the competent person
- ◆ Provide local authorities, media and Govt. adequate factual information through in-company modalities.

5.16 Communication Systems Network

An efficient and reliable communication system is required for the success of the emergency plan. The efficient communication system is required to alert:

- ◆ Emergency Authorities and Services
- ◆ Neighbouring area and public in the vulnerable zone
- ◆ The communication system requires the following:

- ◆ Communication between Control Room to other units in the terminal
- ◆ Hotlines between Control Room to Emergency Services, Meteorological Station and the mutual aid members
- ◆ Paging system and alarm for with the Control Room for alerting the employees
- ◆ P&T Telephone lines

A communication flow chart is to be prepared and kept in the Control Room. An up-to-date Telephone Directory of key personnel concerned with the emergency should be available at all times. These matters should be documented and kept within the Disaster Management Plan manual.

The Disaster Management Plan Manual is required to maintain a record of police stations, hospitals and fire brigade stations in the area to seek assistance in dealing with emergency situations. The emergency team of CEIL should liase with these agencies and with district officials and furnish them information on the possible hazards, extent of damage & actions to be taken by them during such emergencies.

5.17 Transportation

In case of the Natural Gas/Crude Oil pipeline, the main criteria for transport vis-à-vis the emergency management are the accessibility and response time to reach a specific location along the pipeline.

Sectionalising valves will be located at the Well Heads and Gas Processing Station. Vehicles from the Gas Processing Facility are required to transport personnel as well as materials and equipments to the incident site. The transportation should include vehicles for transporting the public in emergency.

For efficient co-ordination, there should be a Communication team in the Control Room to ensure that all the modes of communication are functional round-the clock during an emergency. A log-book for the messages received in/out and actions taken should be maintained.

5.18 Role of External Services

5.18.1 Police

The Police should assist in cordoning off the accident site, organise evacuation and removing any seriously injured people to the hospitals. They shall divert traffic as and when necessary.

5.18.2 Fire brigade

The fire brigade shall organise to fight fires other than gas fires and provide assistance as required.

5.18.3 Hospitals and Doctors

Hospitals and doctors should treat any injuries, which may primarily be burn injuries.

5.19 Mutual Aid from Neighbouring Installations

CEIL may also depend on the facilities of the other industries in the locality for handling emergencies. They will have to arrange with the local administration for providing services, such as fire fighting and medical needs during incident particularly in the nearby regions.

Telephone links with neighbouring industries and customer facility control rooms should be established.

5.20 Public Information System

During a crisis following an incident, the people of the area and a large number of media representatives would like to know about the situation from time to time and the response of the district authority to the crisis. It is important to give timely information to the public in order to prevent panic and rumours. The emergency public information could be carried out in three phases.

5.20.1 Before the Crisis

This will include the safety procedure to be followed during an emergency through posters, talks and mass media in different languages including local language. Leaflets containing do's/don'ts should be circulated to educate the people in the vicinity

5.20.2 During the Crisis

Dissemination of information about the nature of the incidents, actions taken and instructions to the public about protective measures to be taken, evacuation etc. are the important steps during this phase

5.20.3 After the Crisis

Attention should be focussed on information concerning restoration of essential services, travel restrictions, etc.

5.21 Fire Fighting System

Release of gas/vapours can lead to fire. In order to deal with such possible situations, there is a need for constant preparedness to mobilise fire fighting and control resources in minimum time. There should be control of all fire fighting resources in the affected areas under the Fire & Safety Officer. The operational response will be co-ordinated from the Central Control Room. The planning for fire fighting should be as follows:

5.21.1 Before the Crisis

- ◆ Proper road and means of escape should be identified
- ◆ Considering the possible hazards, there must be adequate water supply
- ◆ Training of the fire fighting personnel
- ◆ Provision of adequate availability of fire fighting facilities is important

5.21.2 During the Crisis

Immediate response to an incident should be co-ordinated by the Control Room by matching all the resources. In a major incident having wide off-site implications, more than one installation may be affected, necessitating concurrent fire fighting operations at a number of places. In this case, the whole area may be divided in different fire zones.

The task of the fire zone commanders is as under:

- ◆ Command and control of all fire fighting resources in the respective fire zones
- ◆ Deployment of additional fire resources allocated by Control Room
- ◆ Co-ordination of fire fighting teams

5.22 Relief to the Victims

Post-incident activities include the relief to the victims. The Public Liability Insurance Act indicates the owner, who has control over handling hazardous substances, to pay specified amounts to the victims as interim relief. The District Collector has a definite role in implementation of the PLI Act, 1991. After proper assessment of the incident, he may invite applications for relief, conduct an enquiry of the claims and arrange for payments of the relief amounts to the victims.

5.23 Checklist for Capability Assessment

The checklist will help in assessing the preparedness, prevention and response

resources capabilities. The points included in the checklist are only indicative and there is a need to closely examine the local requirements while preparing the checklist.

For good control and management of an incident, there are three important requisites.

- ◆ Defined Organisation
- ◆ Effective means
- ◆ Trained people

The organisation has to be properly structured for routine as well as emergency purposes with clear understanding of duties and responsibilities. The structure has to consider an execution and speedy implementation of the response plans; while at the same time, it should be flexible enough to tune itself to the fast changing situations. All plans and procedures for emergency handling should be established.

Means include equipment and materials, transport and communication. Identification, storage and upkeep of these means are essential for speedy implementation of the response plans.

People form the vital element in emergency response. Experience, education and training should help make this vital element effective.

In general, the duties, responsibilities and competence of the individual team are defined by the description of the function.

A broad outline of responsibilities and duties of different managers concerning the emergency management plan are given below:

Roles and Responsibilities of Various Emergency Response Team Members

Role	Responsibility
Incident Controller (IC)	- Responsible for overall control of emergency - Liaise with external agencies for any additional help - Reports to statutory agencies about the emergency
Operations Co-ordinator (OC)	- Responsible for control of emergency at site - Liaise with fire and safety co-ordinator in effective control of emergency
Fire & Safety Co-ordinator	- Responsible for carrying out fire fighting and rescue work at the incident site - Co-ordinate with IC and other teams for effective control in minimum possible type
Services Co-	- Responsible for upkeep of equipments and facilities

ordinator	- Provides necessary support for identifying and rectifying the faults and bring the systems online
Communication Co-ordinator	- Ensure proper working of the communication facilities during an emergency - Responsible for internal and external communication as instructed by CC - Log the sequence of events and actions taken
Logistics Co-ordinator	- Responsible for providing support for the transportation of men, material, food etc. - Liaise with chief co-ordinator for mobilizing external emergency services
Medical Incharge	- Responsible for treatment of casualties involved in the incident during emergency control operation - Liaise with hospitals for future treatment

5.24 Disaster Management Plan: Offsite

An unexpected emergency on site could also affect people, livestock and property in the area outside the boundary limits depending on the severity of the incident. This calls for the necessity of developing an offsite emergency preparedness program so as to address any such possible eventuality.

The scope of the offsite plan is to protect the people around and evacuate them if necessary. The district collector is responsible for preparation of an offsite disaster management plan and CEIL shall provide all the required information related to their operations for preparation of the plan.

5.25 Warning System

In an off-site management plan, one of the most important prerequisites is a good 'Warning System'. Efficient warning system will save lives, prevent injuries and reduce losses. The Emergency Co-ordinator - Onsite in consultation with Emergency Co-ordinator Offsite will decide the appropriate warning system and implement it.

The warning systems are of the following types:

- ◆ Disaster Warning (Maximum Credible Loss Scenario) High pitched continuous wailing siren
- ◆ Fire/Toxic Release
- ◆ Long siren followed by short siren
- ◆ All Clear

Depending upon the nature of hazards and the area affected, other methods of warning may be used as follows:

- ◆ Out-door warning sirens
- ◆ Public address system with police
- ◆ ARP sirens
- ◆ Mass media
- ◆ Door to door visit by Civil/Defence Personnel
- ◆ Telephone contact with schools and other organisations/public institutions
- ◆ Information to be provided at common gathering places such as village canteens, shops, etc.

5.26 Services Support System

A major off-site incident may affect a number of units and the surrounding colonies. Hence in addition to the communication, warning, public information, fire fighting system, following additional service support will be required:

- ◆ Health and medical services
- ◆ Transportation services
- ◆ Security and police
- ◆ Media
- ◆ Mutual aid services

A telephone directory containing the contact numbers of all these support services should be documented and be part of the offsite disaster management plan.

