

# The Esso Longford Gas Plant Accident

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## Report of the Longford Royal Commission

Mr Maryl Michael Dawson, AC KBE CB - Chairman

Mr Brian John Brooks, BE FIEAust FAIP FAIE FIE - Commissioner



## **The Esso Longford Gas Plant Accident Report of the Longford Royal Commission**

The Honourable Sir Daryl Michael Dawson, AC KBE CB—Chairman

Mr Brian John Brooks, BE FIEAust FAIP FAIE FIE—Commissioner

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Cover: *Photograph of explosion at 13:00:43 taken from the Longford facility guardhouse camera*

# Longford Royal Commission

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The Hon Sir Daryl Dawson AC, KBE, CB, Chairman  
Mr Brian Brooks BE, FIEAust, FAIP, FAIE, FIE, Commissioner

His Excellency, The Honourable Sir James Gobbo AC  
Governor of the State of Victoria

Your Excellency

By letters patent dated 20 October 1998 you issued to us a Commission to inquire into and report upon the causes of the explosion and fire which occurred at the gas production and processing facility operated by Esso Australia Resources Ltd at Longford. A copy of the letters patent containing the Terms of Reference of the Commission is attached hereto.

That Commission required us to furnish a report not later than 15 February 1999. The time for furnishing the report was, on 9 February 1999, extended to 30 June 1999.

We have completed our inquiry and accordingly furnish you with our report.

Dated this 28<sup>th</sup> day of June 1999.



**Daryl Dawson**  
Chairman



**B.J. Brooks**  
Commissioner





**ELIZABETH THE SECOND BY THE GRACE OF GOD  
QUEEN OF AUSTRALIA AND HER OTHER REALMS AND TERRITORIES  
QUEEN, HEAD OF THE COMMONWEALTH**

To     The Honourable Sir Daryl Michael Dawson, AC, KBE, CB.  
          Brian John Brooks BE, FIEAust, FAIP, FAIE, FIE

GREETINGS:

WHEREAS:

- A.     Gas extracted by Esso Australia Resources Ltd (“Esso”) and BHP Petroleum (Bass Strait) Pty Ltd (“BHP”) is processed at gas production and processing facilities at Longford, Victoria (“the Longford facilities”) operated by Esso.
- B.     On Friday 25 September 1998 an explosion and fire occurred at the Longford facilities.
- C.     As a result of that explosion and fire two persons were killed, a number of persons were injured and all gas supply from the Longford facilities ceased.
- D.     It appeared to the Governor in Council that the available supply of gas was or was likely to become less than was sufficient for the reasonable requirements of the community and accordingly the Governor in Council, acting under s.62F of the *Gas Industry Act 1994* (“the Act”) by proclamation declared that Part 6A of the Act was to apply.
- E.     Following that proclamation, directions were given under Part 6A of the Act to effect the cessation of all but essential gas usage in those parts of Victoria which rely upon the supply of gas from the Longford facilities.
- F.     The Governor of the State of Victoria, in the Commonwealth of Australia by and with the advice of the Executive Council has deemed it to be expedient that a Commission should issue to you in the terms set out below.

NOW THEREFORE the Governor of the State of Victoria, in the Commonwealth of Australia, by and with the advice of the Executive Council and acting pursuant to section 88B of the *Constitution Act 1975*, appoints and constitutes you

The Honourable Sir Daryl Michael Dawson AC, KBE, CB  
Brian John Brooks BE, FIEAust, FIAP FAIE, FIE

to be Our Commissioners

AND HEREBY APPOINTS The Honourable Sir Daryl Michael Dawson, AC, KBE, CB to be Chairman of the Royal Commission.

FOR THE PURPOSE of inquiring into and reporting upon the following matters:

1. What were the causes of:
  - (a) the explosion and fire which occurred at the Longford facilities on Friday 25 September 1998;
  - (b) the failure of gas supply from the Longford facilities following that explosion and fire.
  
2. Whether any of the following factors caused or contributed to the occurrence of that explosion, fire and failure of gas supply, namely:
  - (a) the design of the Longford facilities including the interdependence of
    - (i) the plants and other components which comprise those facilities;  
and
    - (ii) the Longford facilities and other facilities at, or upstream of, the Esso site at Longford;
  - (b) operating standards, practices and policies;
  - (c) maintenance standards, practices and policies;
  - (d) asset management practices and policies;
  - (e) risk management procedures and emergency procedures in force at the time of that occurrence;
  - (f) any relevant changes in the standards, practices and policies referred to in subparagraphs (b), (c), (d) and (e) which has taken place before that occurrence;
  - (g) the hydrate incident at the Longford facilities which occurred in June 1998, and any other previous incidents considered by the Board to be relevant;
  - (h) whether there was any breach of, or non-compliance with, the requirements of any relevant statute or regulation by Esso or BHP.
  
3. What steps should be taken by Esso or BHP to prevent or lessen the risk of:
  - (a) a repetition of the incidents which occurred at the Longford facilities on 25 September 1998; or
  - (b) a further disruption of gas supply from those facilities;

AND WE direct you to make such recommendations arising out of your inquiry as you consider appropriate, including recommendations regarding any legislative or administrative changes that are necessary or desirable.

AND WE do by these presents give and grant you full power and authority to call before you such person or persons as you shall judge likely to afford you any information upon the subject of this Our Commission, and to inquire of and concerning, the premises by all other lawful ways and means whatsoever.

AND WE declare that the powers of the Commission at the discretion of the Chairman may, at any time, be exercised by one or more Commissioners.

AND WE will and command that this our Commission shall continue in full force and virtue and that you shall and may from time to time and at every place or places proceed in the execution thereof, and of every matter and thing therein contained although the same be not continued from time to time by adjournment.

AND WE direct you to conduct your inquiry as expeditiously as possible and, not later than 15 February 1999 or such later date as WE may be pleased to fix, to furnish US a report of the results of your inquiry and of your recommendations.

IN TESTIMONY WHERE OF WE have caused these Our Letters to be made Patent and the Seal of our State to be hereunder affixed.

WITNESS His Excellency the Honourable Sir James Augustine Gobbo, Companion of the Order of Australia, Governor of Victoria and its dependencies in the Commonwealth of Australia at Melbourne this 20th day of October One thousand nine hundred and ninety eight in the forty-seventh year of Our reign.

JAMES GOBBO  
By His Excellency's Command  
J.G.KENNETT  
Premier of Victoria

Entered on record by me in the register of Patents Book No.41 Page No 166 on the twentieth day of October 1998.

BILL SCALES  
Secretary, Department of Premier and Cabinet.





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# Chapter 1

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## INTRODUCTION

- 1.1 At Longford in south-eastern Victoria, Esso Australia Resources Ltd (Esso) operates three gas plants to process gas flowing from wells in Bass Strait. It also operates a Crude Oil Stabilisation Plant (CSP) at Longford to process oil flowing from other wells in Bass Strait. The gas plants are known as Gas Plant 1 (GP1), Gas Plant 2 (GP2) and Gas Plant 3 (GP3). They are numbered in the order in which they were built, starting with GP1, which commenced production in March, 1969.
- 1.2 Esso is a subsidiary of the Exxon Corporation (Exxon), which is incorporated in the United States of America. Under an operating agreement, Esso operates the wells in Bass Strait and the plants at Longford on behalf of a joint venture with BHP Petroleum (Bass Strait) Pty Ltd (BHP). BHP is a subsidiary of The Broken Hill Proprietary Company Ltd. It takes no part in the actual operation of the plants.
- 1.3 On Friday, 25 September 1998, at about 12.26 in the afternoon, a vessel in GP1 fractured, releasing hydrocarbon vapours and liquid. Explosions and a fire followed. Two Esso employees, Peter Bubeck Wilson and John Francis Lowery, were killed. Eight others were injured. Supplies of natural gas to domestic and industrial users were halted.
- 1.4 The vessel which failed was a heat exchanger, GP905. It was also known as a demethaniser reboiler because it operated to heat rich oil at the bottom of a piece of equipment known as a Rich Oil Demethaniser (ROD). Near GP905 was another heat exchanger, GP922, which preheated rich oil flowing from the ROD on its way to the Rich Oil Fractionator (ROF). GP922 had developed leaks at its flanges some time before the accident and attempts were being made to repair them at the time GP905 failed.
- 1.5 Immediately before its failure, the temperature of GP905 was well below its normal operating temperature and may have been as low as  $-48^{\circ}\text{C}$ . The normal operating temperature was in the vicinity of  $100^{\circ}\text{C}$ . The low temperature of GP905 was due to the loss of lean oil flow in GP1. Hot lean oil flowing through GP905 was the means by which it was heated to its normal operating temperature.

- 1.6 The lean oil flow in GP1 stopped when the pumps known as the GP1201 pumps tripped and were not restarted. Notwithstanding the loss of lean oil flow, cold rich oil and, subsequently, cold condensate continued to flow through GP905 causing its temperature to drop.
- 1.7 The GP1201 pumps were out of operation for some hours. When they were eventually restarted there was a flow of warm lean oil into GP905 for a short time. The higher temperature of the lean oil flowing into the cold reboiler caused stress in the vessel. This resulted in its brittle fracture at one end.
- 1.8 The rupture of GP905 released a large volume of hydrocarbons in the form of vapour. The vapour subsequently ignited giving rise to a series of explosions and fire. The fire was not fully extinguished until 27 September 1998.
- 1.9 Because of the explosions and fire, all three gas plants at Longford were shut in and supplies of gas ceased. The final restoration of gas supply to all consumers took place by 14 October 1998.
- 1.10 The Commission is required by its Terms of Reference to inquire into and report upon the causes of the explosion and fire and what steps should be taken by Esso or BHP to prevent or lessen the risk of a repetition of the accident or a further disruption of gas supply from the facilities at Longford. The means by which the Commission carried out its task and the facilities which were required to enable it to do so are detailed in Appendix 1 to this report.

# Chapter 2

## LONGFORD

### THE PROCESS

- 2.1 GP1 was a refrigerated lean oil absorption plant. By using low temperatures and high pressures, it employed lean oil to absorb hydrocarbon components from incoming gas. Lean oil is a light oil similar to aviation kerosene. It does not contain methane, ethane, propane or butane. When lean oil absorbed these hydrocarbons, it became rich oil. Using lower pressures and higher temperatures, the rich oil was then distilled to release the methane, which was returned to the gas stream, and a mixture of ethane, propane and butane for further processing into different products. After releasing these products the rich oil became lean oil once more and the process began again. A simplified flow chart showing the GP1 process and its interconnections with other plants at Longford is provided in Appendix 3.

### Incoming Gas

- 2.2 Longford's inlet gas comes from three main fields offshore in Bass Strait: Marlin, Barracouta and Snapper. The Marlin and Barracouta fields came on line in 1969 and the Snapper field in 1981.

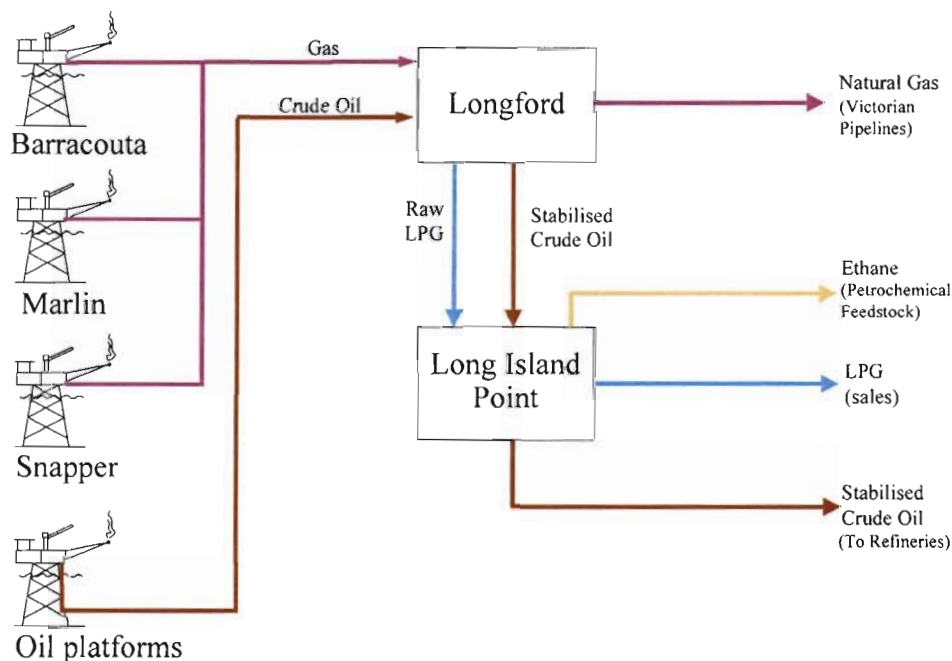


Figure 2.1 Simplified diagram of gas and oil flows from the platforms to end users



- 2.3 The gas and associated hydrocarbon condensate is delivered by pipeline to the onshore processing facilities at Longford and Long Island Point (LIP). Those facilities are designed to separate products with a commercial value from the inlet gas and condensate. Those products are natural gas, which consists principally of methane; ethane, which is used in the petrochemical industry; and liquefied petroleum gas (LPG), which consists principally of propane and butane. The heavier hydrocarbons that are left are fed into the CSP adjacent to the gas plants at Longford. Natural gas is sent by pipeline from Longford to domestic and industrial users in Melbourne and elsewhere in Victoria. A mixture of ethane, propane and butane (known as raw LPG) is sent by another pipeline to LIP outside Melbourne where the ethane is separated from the LPG and piped to petrochemical plants operated respectively by Huntsman Chemical Company Pty Ltd at Footscray and by the Kemcor group of companies at Altona. The propane and butane are separated and both are exported or sold locally.
- 2.4 In 1969 when the facility at Longford was established, there was only one gas plant (GP1) and a crude stabilisation plant. The commissioning of GP2 in 1976 and GP3 in 1983 enhanced the site's capacity. GP2 and GP3 used newer technology to process the gas, namely, a cryogenic process. This process does not use absorption oil. Instead, a series of expansions and liquid separations followed by recompressions are used to remove the ethane and heavier components. Some sections of this cryogenic process are designed to operate at very low temperatures, well below those found in GP1.
- 2.5 As the raw gas is piped from offshore, it cools and its pressure is lowered. Under these conditions both water and hydrocarbons condense to form quantities of liquid which accumulate in the lower parts of the pipeline when gas flowrates are low. Some parts of the pipeline are lower than others because the pipeline follows the contours of the sea bed on which it rests. These aggregations of liquid are known as slugs and can weigh up to several tonnes.

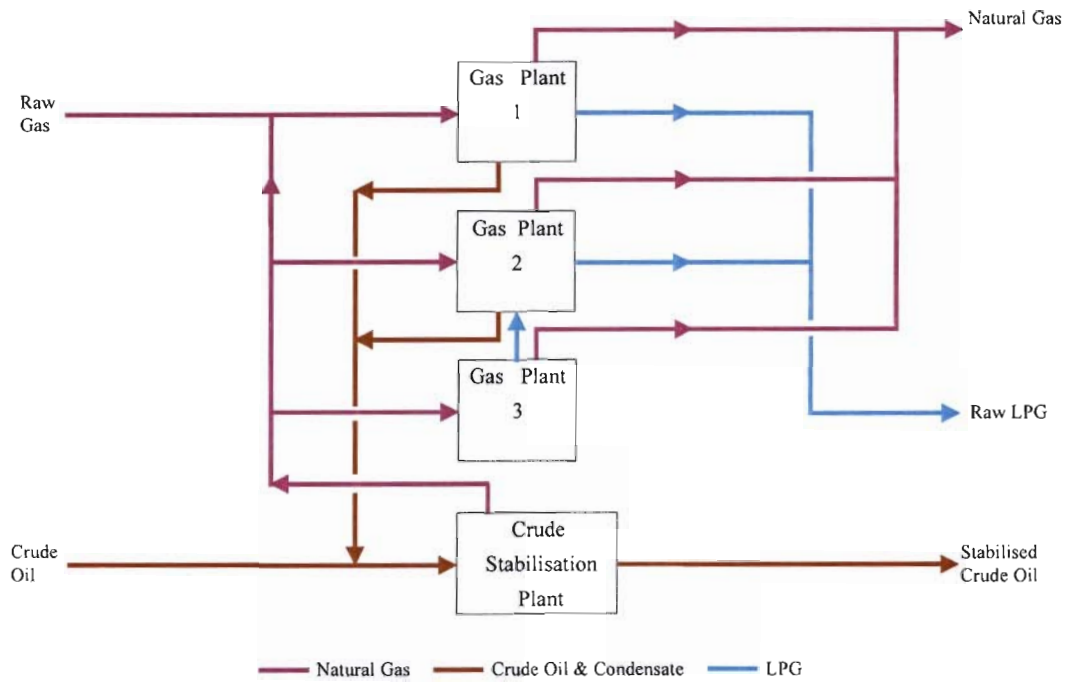


Figure 2.2 Overview of primary hydrocarbon flows to and from the Longford operating units

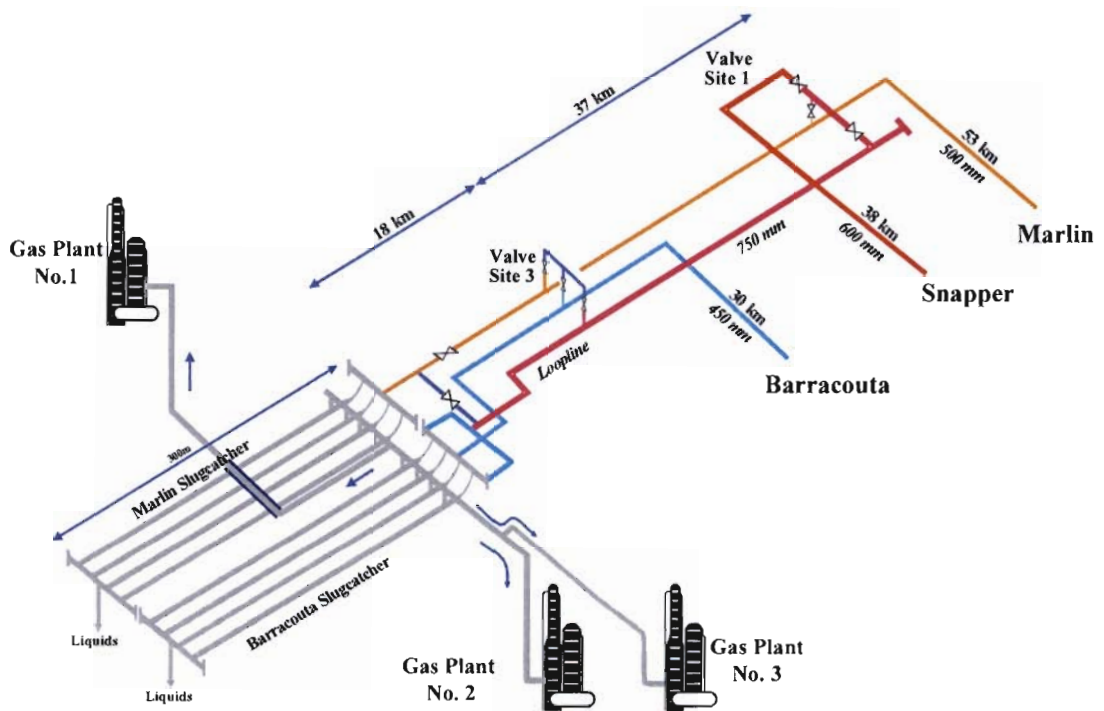


Figure 2.3 Gas pipelines and the Longford slugcatchers

2.6 At the plant's gas inlet there is a device known as a slugcatcher, which is employed to dissipate the energy of the slugs as they arrive at Longford and to store the liquids prior to processing. In fact, there are two slugcatchers at Longford, the Barracouta Slugcatcher and the Marlin Slugcatcher, but they are operated as one. The names reflect the initial use of one slugcatcher to serve the Barracouta platform and the other to serve the Marlin platform, but they were no longer used in this manner on 25 September 1998. A slugcatcher consists of a number of heavy walled pipes or barrels of large diameter into which the incoming gas stream, containing liquid, is fed. (See Figure 2.3). The gas and liquids enter the slugcatcher barrels through relatively small, curved pipes known as tusks, which accelerate the flow of the mixture into the barrels. These barrels slope downward from the inlet to the discharge end. The gas, which has a lower density than the liquids, is withdrawn through pipes at the top of the slugcatcher while the liquid passes through the barrels where it decelerates, thus removing the energy contained in any slugs. The liquid is stored in the lower end of the barrels to await processing. Longford has eight slugcatcher barrels, each 265 metres long and 1.07 metres in diameter, to provide the surge capacity for the incoming slugs.

2.7 Water is drained off the bottom of the slugcatchers and processed to recover glycol added offshore. The remaining condensate, or condensed hydrocarbons, flows to the Crude De-ethaniser in GP1 or to the Feed Liquid Stripper in GP2. The gas taken from the top of the slugcatchers to the three gas plants passes through an inlet separator in each plant, which removes any free water and condensate. The gas then passes through molecular sieves in each plant to remove water vapour and hydrogen sulphide. The GP1 inlet gas was chilled by means of two heat exchangers, GP901 and GP902, to prepare it for the absorption process, which was better performed at cold temperatures. Figure 2.4 shows a simplified overview of GP1.

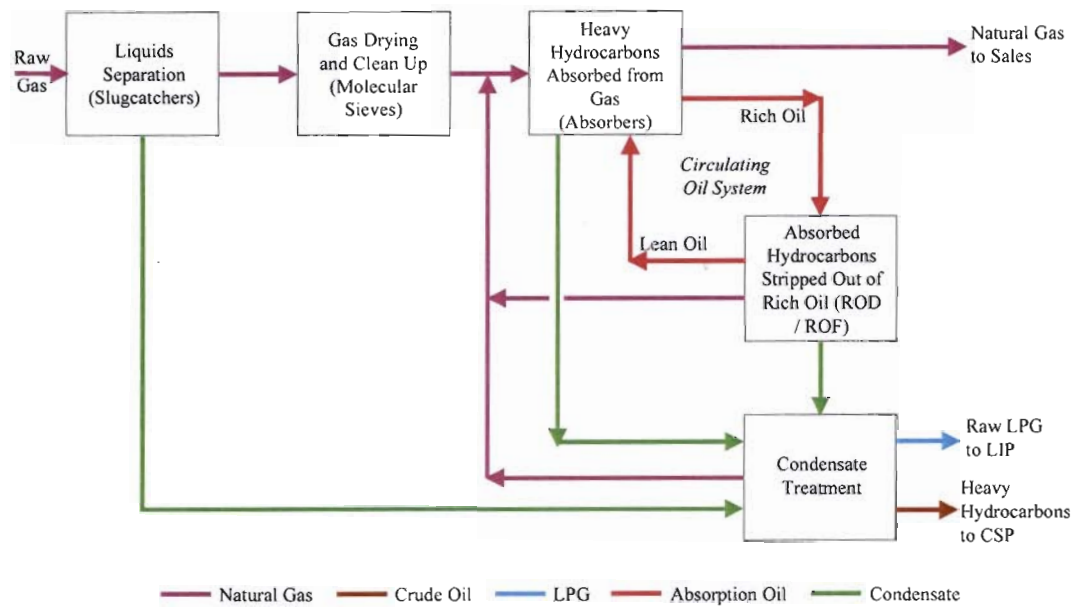


Figure 2.4 Simplified overview of GPI and its process sections

### Absorbers

2.8 GPI was equipped with two identical absorbers, designated A and B, which operated in parallel. The gas was fed into the lower part of the absorbers at a temperature of  $-25^{\circ}\text{C}$ . An absorber is a tower with a number of valve trays inside. These allow gas to travel up and lean oil, presaturated with methane, to travel down the tower. Lean oil was fed into the top of the tower at a temperature of  $-20^{\circ}\text{C}$ . As the lean oil dropped from tray to tray, it absorbed much of the ethane, propane and butane contained in the gas travelling up through the valves in the trays. By this process, the lean oil became rich oil (i.e. saturated with heavier hydrocarbons: ethane, propane and butane), which was taken from the absorber when it reached the rich oil trap tray (i.e. the second lowest tray).

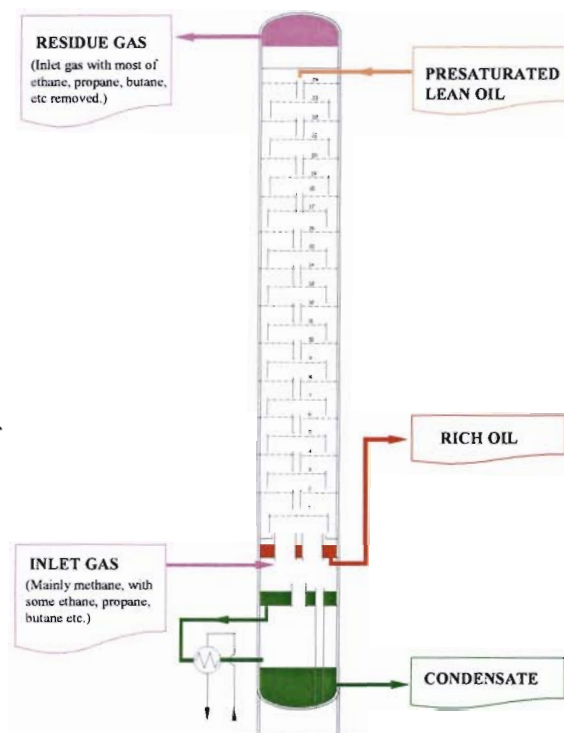
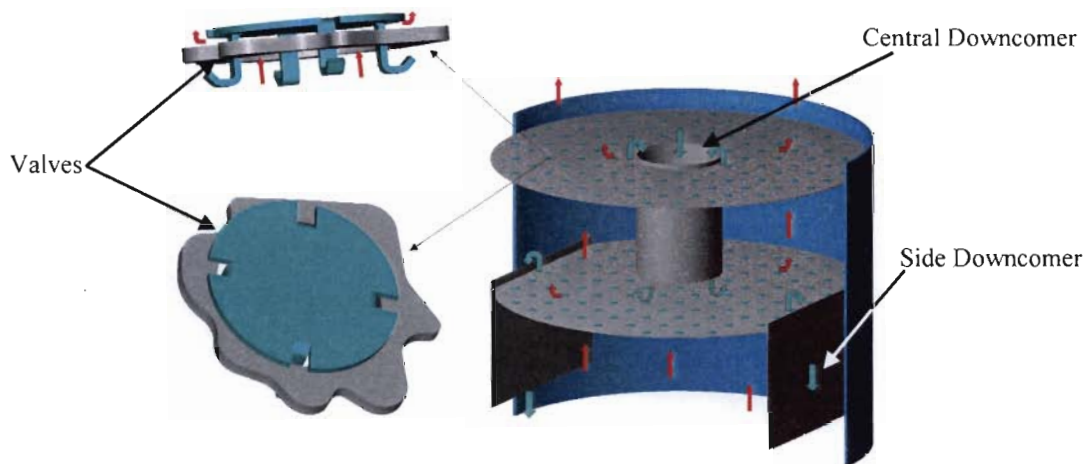
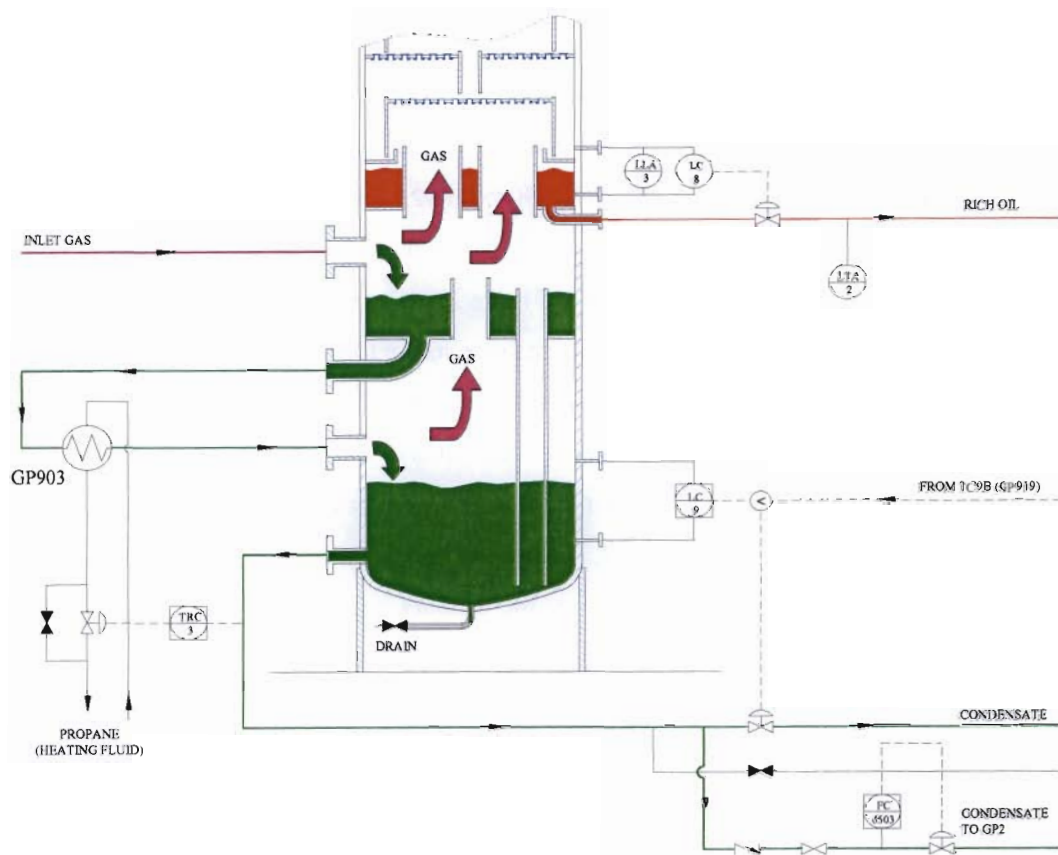


Figure 2.5 Schematic diagram of an absorber



*Figure 2.6 Schematic diagram of absorber trays*

- 2.9 Gas entered the lower part of the absorbers carrying with it a quantity of condensate formed during the chilling process. This condensate dropped to a separate tray at the bottom of each absorber. From there it went to a reboiler to be heated in order to drive off as much methane as possible. Ethane and some propane were also vaporised with the methane. This methane and the other heavier gases joined the gas travelling up the absorber. The gas which was not absorbed by the lean oil flowing down the absorber was mostly methane and this was taken off at the top of the absorber to be sold as natural gas. The remaining condensate was piped from the base of the absorber to a flash tank, known as GP1105A, after passing through a heat exchanger known as GP919. A portion of the remaining condensate could also be directed to a demethaniser in GP2 where more effective ethane recovery was possible.
- 2.10 The heating of the condensate at the bottom of each of the absorbers was carried out by means of heat exchangers known as reboilers (GP903A and B). Each reboiler was in the form of a shell through which a number of tubes ran. Warm liquid propane was circulated in the shell around the tubes. The condensate passing to the bottom of the absorber flowed through the tubes and back to the absorber. In passing through the tubes it was warmed by the propane surrounding the tubes in the shell. When the flow of warm propane was increased, the temperature of the condensate also increased and more condensate was vaporised. A small increase in temperature corresponded to a significant increase in vaporisation. The condensate temperature was therefore adjusted by the operator to control the proportion of condensate that was vaporised. If temperatures in the bottom of the absorber were allowed to drop, there was less vaporisation and a corresponding increase in the production of condensate in the absorber.



**Figure 2.7 Fluid flows at the bottom of an absorber**

- 2.11 Although the two absorbers each performed the same function, it is convenient to confine this description for the most part to Absorber B, which played a major role in the events of 25 September 1998. The reboiler associated with Absorber B was GP903B. The temperature of the condensate in the bottom of Absorber B was regulated by a temperature control system, known as TRC3B, which, by means of an automatic valve, controlled the flow of warm propane liquid to GP903B. By this means the temperature of the condensate was held at a level set on the TRC3B controller in the control room. There was a valve which could be manually operated by the area operators to bypass the automatic TRC3B valve, when necessary, to control the amount of propane flowing into GP903B and hence the temperature of the condensate in the bottom of Absorber B.

### ***ROD/ROF Area***

- 2.12 The rich oil leaving the absorbers was dropped in pressure through the level control valves LC8A and LC8B and then flowed to a flash tank, known as the Rich Oil Flash Tank, or GP1108, where some of the methane gas which had flashed off from the rich oil was separated. This methane was compressed and most of it was recycled to the inlet of the plant. Some, however, was taken off to be used as fuel in GP1.

2.13

The rich oil from GP1108 was taken in two streams to the ROD through a series of heat exchangers known as GP904, GP924, GP925 and GP930. One stream (the rich oil cold feed) was taken through GP924 and fed into the ROD at  $-30^{\circ}\text{C}$ . The other stream (the rich oil warm feed) passed through GP904, GP925 and GP930 and entered the ROD at  $10^{\circ}\text{C}$ . The rich oil was fed into the centre part of the ROD tower. A diagram of the ROD and associated equipment is shown in Figure 2.8. Heavier components moved to the bottom of the tower and the lighter components rose to the top. At the bottom of the tower the rich oil was heated by means of a reboiler known as GP905. This was the vessel that failed on 25 September 1998. The source of the heat was hot lean oil, which flowed through GP905 on the shell side. Rich oil from the ROD flowed through the tubes in GP905 and back to the ROD. A stream of lean oil, known as reflux, was fed into the top of the ROD at a temperature of  $-20^{\circ}\text{C}$ . By the time the vapours caused by the heating of the rich oil reached the top of the ROD, the temperature had dropped sufficiently so that only methane and a little ethane was left. The heavier hydrocarbons had condensed and flowed to the bottom of the tower as rich oil. The methane from the top of the ROD joined the lean oil stream delivered by pumps GP1201A, B and C and flowed to the Oil Saturator Tank. (There were three booster pumps known as GP1201A, B and C, of which two were normally operating, with one on standby). The Oil Saturator Tank was known as GP1110. From there any methane not absorbed into the lean oil stream was separated, recompressed and delivered to the inlet of GP1 or GP2.

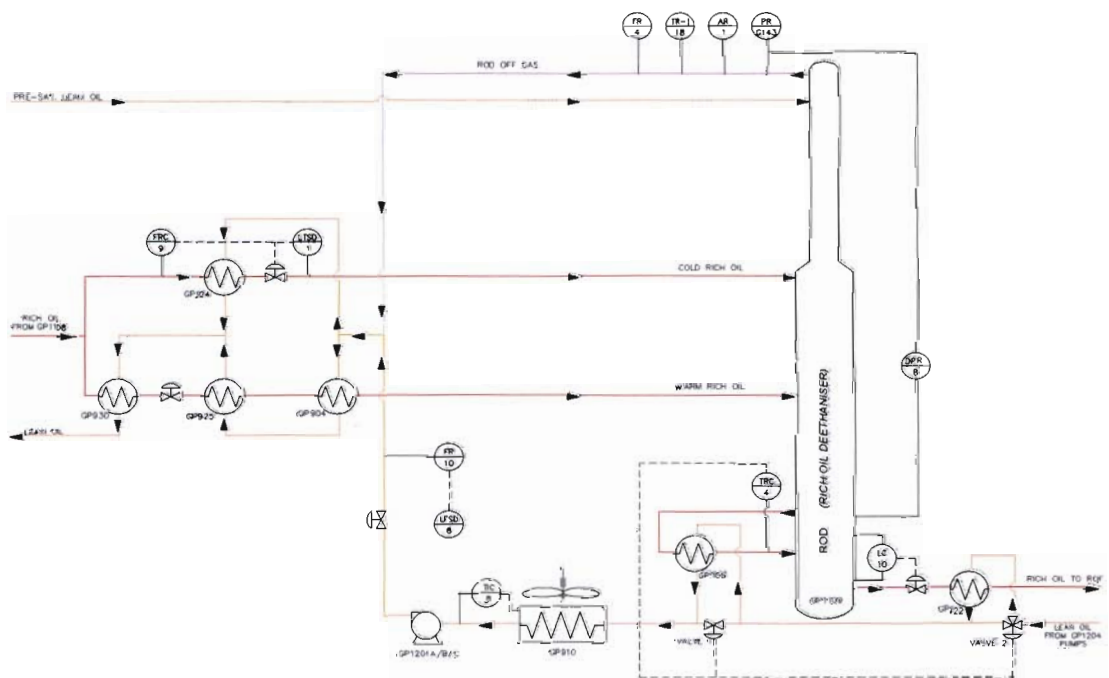


Figure 2.8 The ROD and associated equipment

- 2.14 The rich oil from the bottom of the ROD flowed through the heat exchanger known as GP922 on its way to the ROF. GP922 was the vessel that was leaking on the day of the accident. It preheated the rich oil going to the ROF by means of hot lean oil on the shell side of the vessel. The rich oil passed through the tubes inside GP922.
- 2.15 There was a temperature control system, known as TRC4, which controlled the temperature at the bottom of the ROD. It did so by regulating the flow of lean oil through GP905 and GP922. If the maximum flow of lean oil through GP905 did not deliver the required temperature in the bottom of the ROD, TRC4 would cause the lean oil to bypass GP922, partially or wholly, so that the lean oil was hotter when it reached GP905.
- 2.16 The rich oil from the ROD was preheated by GP922 (if not bypassed) and entered the ROF tower at 140°C. Some lighter components were vaporised at that stage with the remaining oil passing down to the bottom of the tower, where it was heated to a temperature of 285°C by means of gas-fired reboilers GP501A and B. These vaporised the remaining ethane, propane and butane. What remained was lean oil. The oil was circulated through the reboilers by pumps, known as GP1204A, B and C. From the delivery of these pumps a stream of lean oil was also taken off and delivered back to the shell side of GP922. The amount of lean oil that was taken off was governed by the rate of pumping from the Oil Saturator Tank.

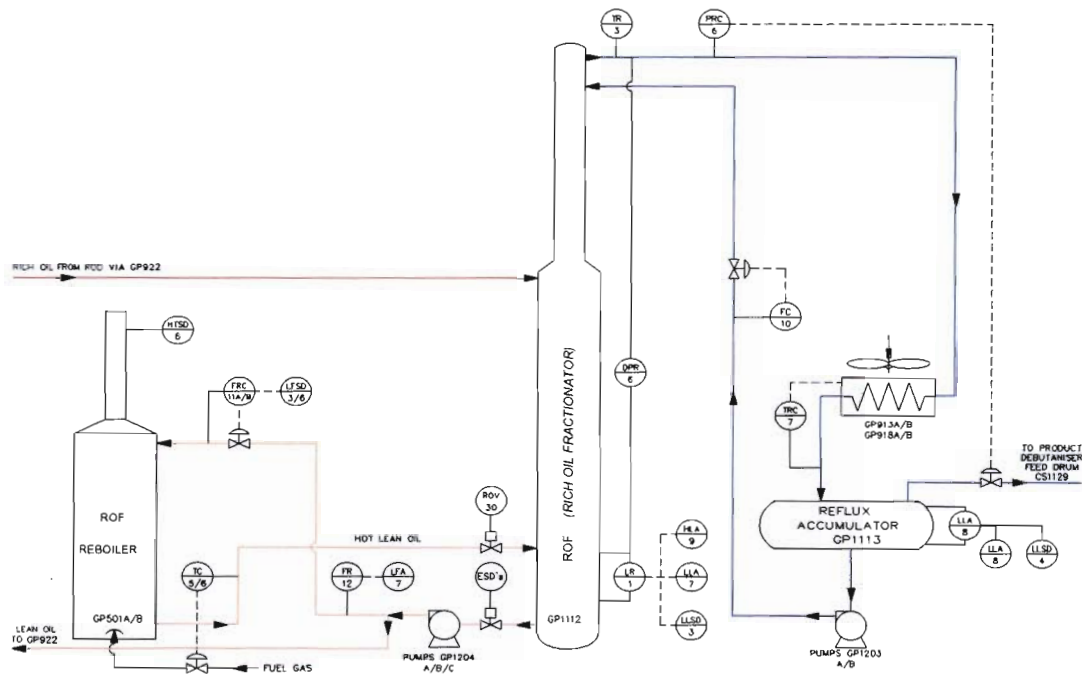


Figure 2.9 The ROF and associated equipment





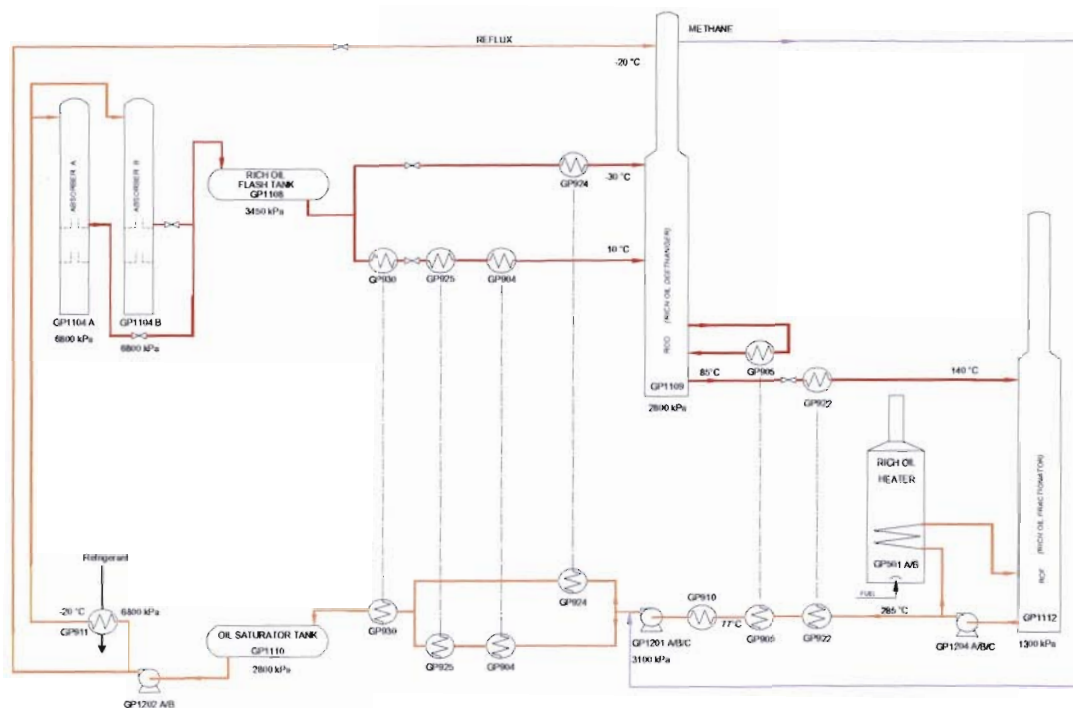
2.17 The vapour at the top of the ROF was at a temperature of about 85°C and flowed to a fin-fan cooler, which was an air-cooled heat exchanger. There it was condensed to a liquid form, being essentially LPG. It then flowed to a reflux accumulator. Some of the liquid (reflux) was returned to the top of the ROF at a temperature of about 55°C, but the bulk went to a product debutaniser in the CSP.

### ***Lean Oil Recycle***

2.18 The lean oil flow, which flowed in the opposite direction to that of the rich oil, can now be described. Lean oil was pumped by GP1204 from the bottom of the ROF, some flowing through a fired reboiler and returning to the bottom of the ROF, with the remainder flowing to GP922 and GP905. There it provided the heat to boil the rich oil in the bottom of the ROD and to preheat the rich oil on its way to the ROF. The lean oil left GP905 at a temperature of about 77°C and was further cooled by a fin-fan cooler, GP910. It was then pumped by a booster pump known as GP1201 through GP904, GP924, GP925 and GP930. By this means the lean oil was further cooled by the cold rich oil passing through the tubes of those heat exchangers.

2.19 However, before the lean oil reached those heat exchangers, the methane from the top of the ROD was injected into the stream so that the lean oil became saturated with methane. This process was assisted by the low temperature to which the lean oil was chilled by the heat exchangers through which it passed. The purpose of presaturating the lean oil with methane was so that the lean oil would not absorb methane when it entered the top of the absorber towers. The absorption process heated the oil, reducing its capacity to absorb heavier components in the gas.

2.20 After the entry of the methane to the lean oil stream and cooling in the heat exchangers, the lean oil went to the Oil Saturator Tank where any methane not absorbed by the lean oil was flashed off to fuel gas or recompressed and fed to the incoming gas stream at the front of the plant.



**Figure 2.10 Lean oil / rich oil circulation**

2.21 The saturated lean oil was transferred from the Oil Saturator Tank by pumps GP1202A and B. Most of this lean oil was sent to the absorbers via a heat exchanger, which was the lean oil chiller known as GP911. This chiller used propane as a refrigerant. It dropped the temperature of the lean oil to approximately  $-20^{\circ}\text{C}$ . At this temperature it entered the absorbers and the process began again. A smaller quantity of the lean oil taken from the Oil Saturator Tank was pumped to the top of the ROD as reflux.

### **Condensate Treatment**

2.22 It is possible now to return to the condensate, which was taken to the Condensate Flash Tank known as GP1105A. Some methane having been flashed from it, the condensate then passed through a heat exchanger known as GP921. There it was heated to a temperature of about  $62^{\circ}\text{C}$  by means of hot condensate coming from an item of equipment known as the Condensate De-ethaniser tower (GP1106A). The hot condensate from GP1106A flowed through the shell side of GP921 and the incoming condensate flowed through the tube side. The heated incoming condensate then entered GP1106A and flowed to the bottom where it was pumped to a gas fired reboiler. The methane and ethane components, which were driven off by this process, flowed from the top of the tower and left as fuel for the gas plant, or were recompressed and returned to the incoming gas stream at the front of GP1 or GP2. The remaining condensate from the bottom of the tower went to the Product Debutaniser in the CSP.

### ***Plant Layout***

- 2.23 Figure 2.11 is a photograph showing the layout of the Longford site. It can be seen that GP1 lies due south of the offices and between the CSP and GP2 and GP3. Figure 2.12 shows the layout of equipment within GP1.
- 2.24 In GP1 there were various pipes carrying process fluids as well as electrical cables and instrument air lines. For the most part these pipes were elevated on a structure known as a pipebridge or piperack. There was an intersection of the main north/south piperack with the main east/west piperack adjacent to the location of GP922 and GP905. Many of the pipes at the intersection carried hydrocarbons. The intersection was known colloquially as Kings Cross.



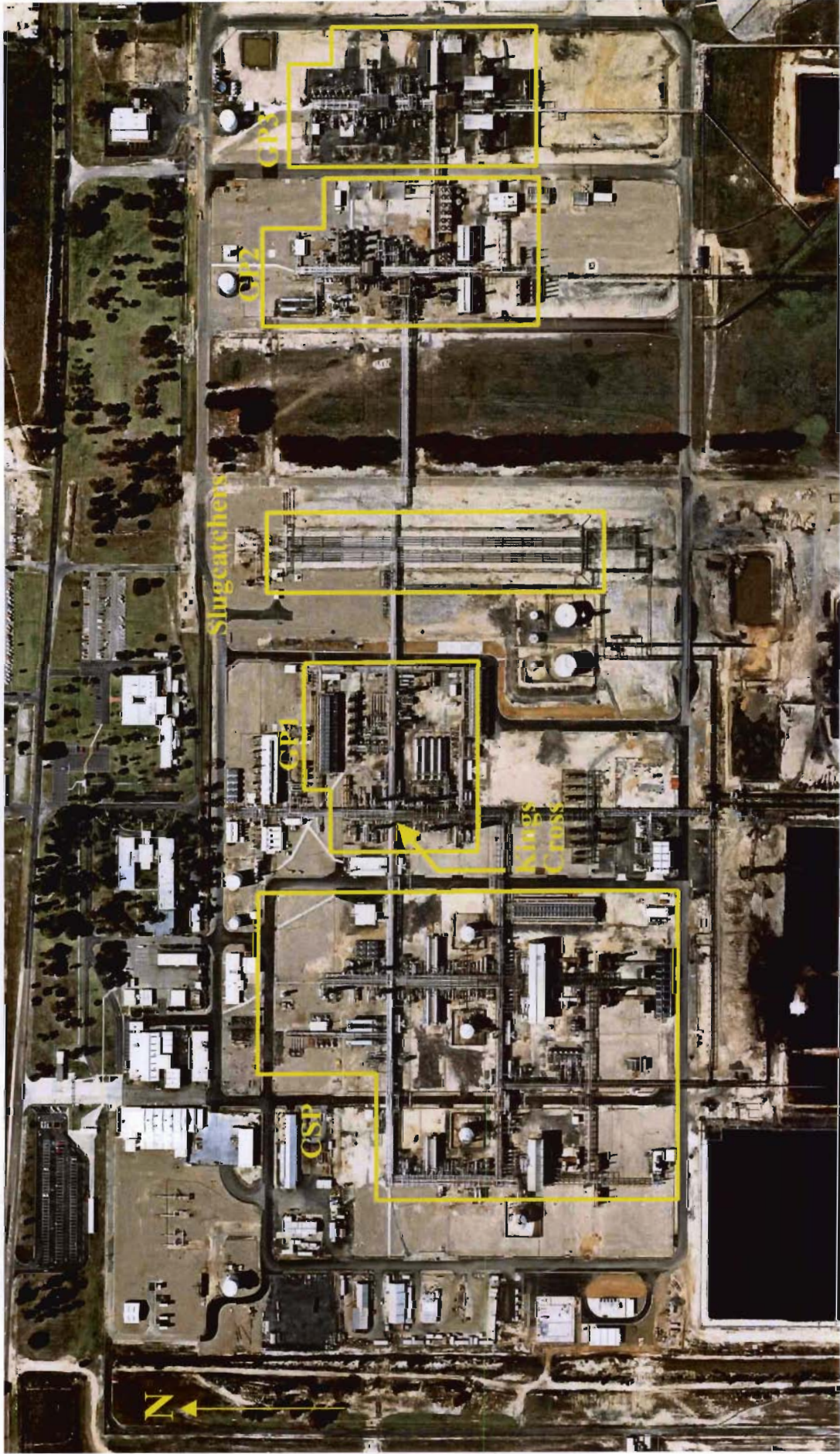


Figure 2.11 Aerial photograph of the Longford facility

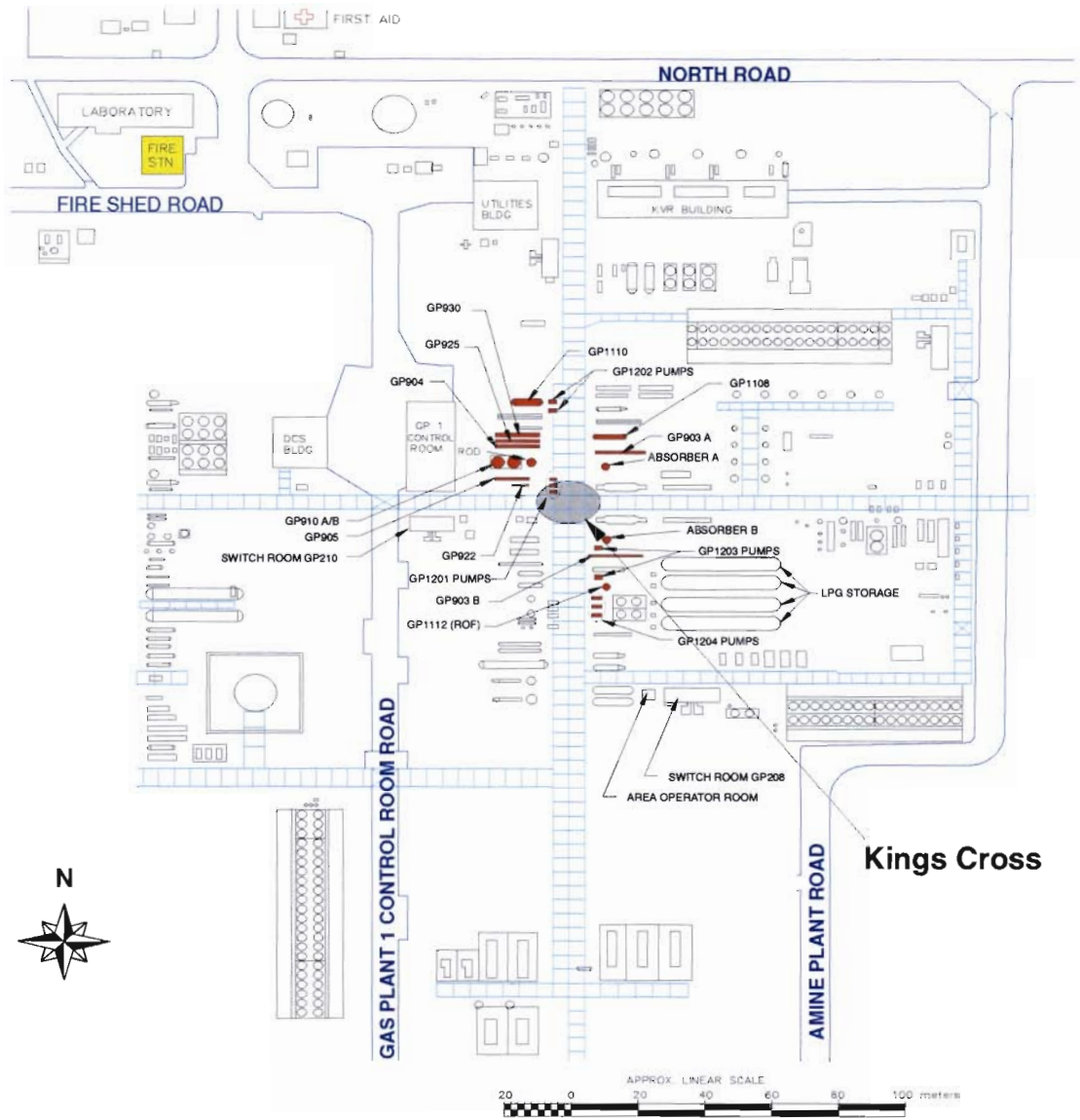


Figure 2.12 Layout of GP1 showing the Kings Cross piperack intersection

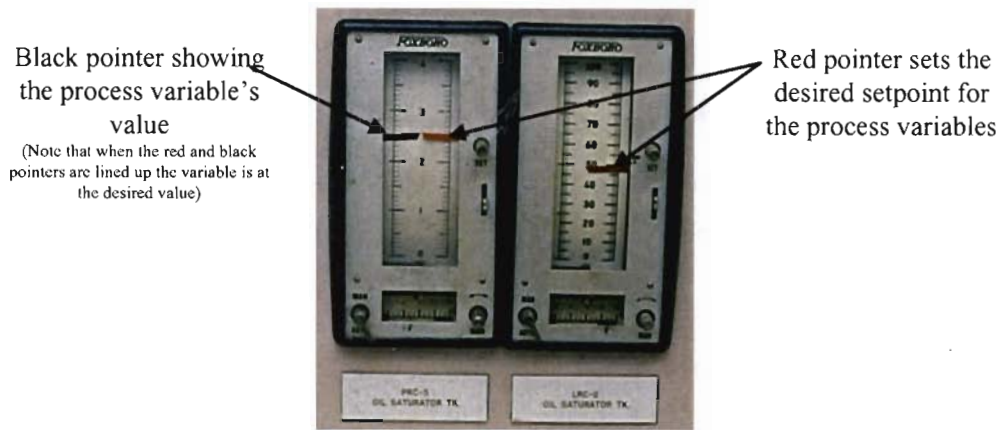
## ***INSTRUMENTATION AND CONTROLS IN GAS PLANT 1***

### ***The Control Room***

- 2.25 The instrumentation in the GPI control room was a mixture of pneumatic equipment installed when the plant was built in 1969 and a computerised system known as the Bailey system.
- 2.26 The pneumatic equipment and associated alarms were mounted on panels around the walls of the control room. They can be seen in Figure 2.13, a photograph taken after the accident of 25 September 1998. The primary pneumatic instruments were controllers that enabled the operators to set the value of the process variable that they wished to control. This was done by moving a red pointer to the appropriate setpoint on the right-hand side of a vertical scale (see Figure 2.14). When the controllers were in operation, a black pointer moved up the left-hand side of the controller to indicate the actual value of the process variable being controlled. When the process was being effectively controlled the black and red pointers would be aligned, making it easy to see whether it was operating properly. An example of this alignment may be seen in Figure 2.14.



***Figure 2.13 Photograph of GPI Pneumatic Control Panel  
(taken after the Bailey equipment was removed for examination)***

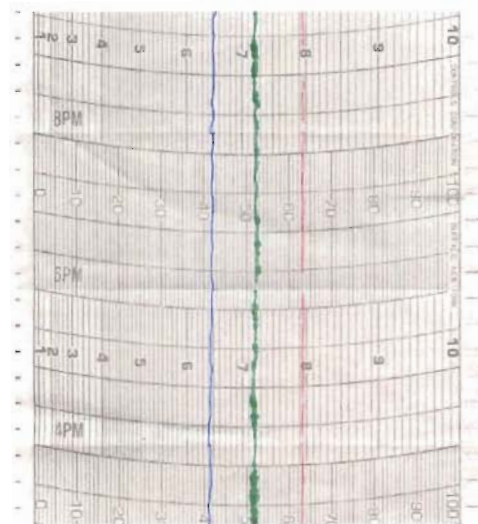


*Figure 2.14 Photograph of pneumatic controller*

2.27 Information was recorded continuously on paper charts (called strip charts) by pneumatic recorders. There were up to three coloured ink pens that recorded up to three separate variables on the one chart. An example of these recorders can be seen in Figure 2.15 and an example of a strip chart is shown in Figure 2.16. A number of strip charts are reproduced in Chapter 5. Alarm panels were provided which gave visible and audible alarms should process variables move out of a predetermined range. Typical examples of such panels are shown in Figure 2.17. The audible alarm could be cancelled by pressing a button, but the visible alarm would stay illuminated until the controlled variable returned to the normal operating range and the operator manually reset the alarm.



*Figure 2.15 A pneumatic recorder in GPI*



*Figure 2.16 Example recorder strip chart*



*Figure 2.17 Photograph of GP1 alarm panels*

2.28 The Bailey system used computer screens and keyboards to set and display the process variables. Various displays on the screens, or pages, were used in GP1 for different aspects of the process. Each part of the process was generally represented by a flow diagram on at least one of the displays. A typical Bailey workstation is shown in Figure 2.18, which is a photograph of the CSP unit in the GP1/CSP control room. Associated alarm panels can be seen to the left and right of the screen. The Bailey screen for the GP1 absorbers is shown in Figure 2.19. The system showed the setpoint and value of the process variable for each process it controlled. It provided more information than a pneumatic system. It also offered more sophisticated control and a higher speed of response than a pneumatic system so that the process variables could be held within closer limits. However, unlike the pneumatic system, it was necessary for the operator to call up a particular display page to check a particular condition. The ultimate movement of control valves was still carried out pneumatically with electrical/pneumatic converters, which converted the electronic signals to pneumatic output at the valves. As with the original panels, audible alarms could be cancelled by pressing a button. However, unlike the original panel, the visual alarm would remain active until the controlled variable returned to normal operating range, whereupon it would reset automatically.





Figure 2.18 Photograph of a typical Bailey workstation

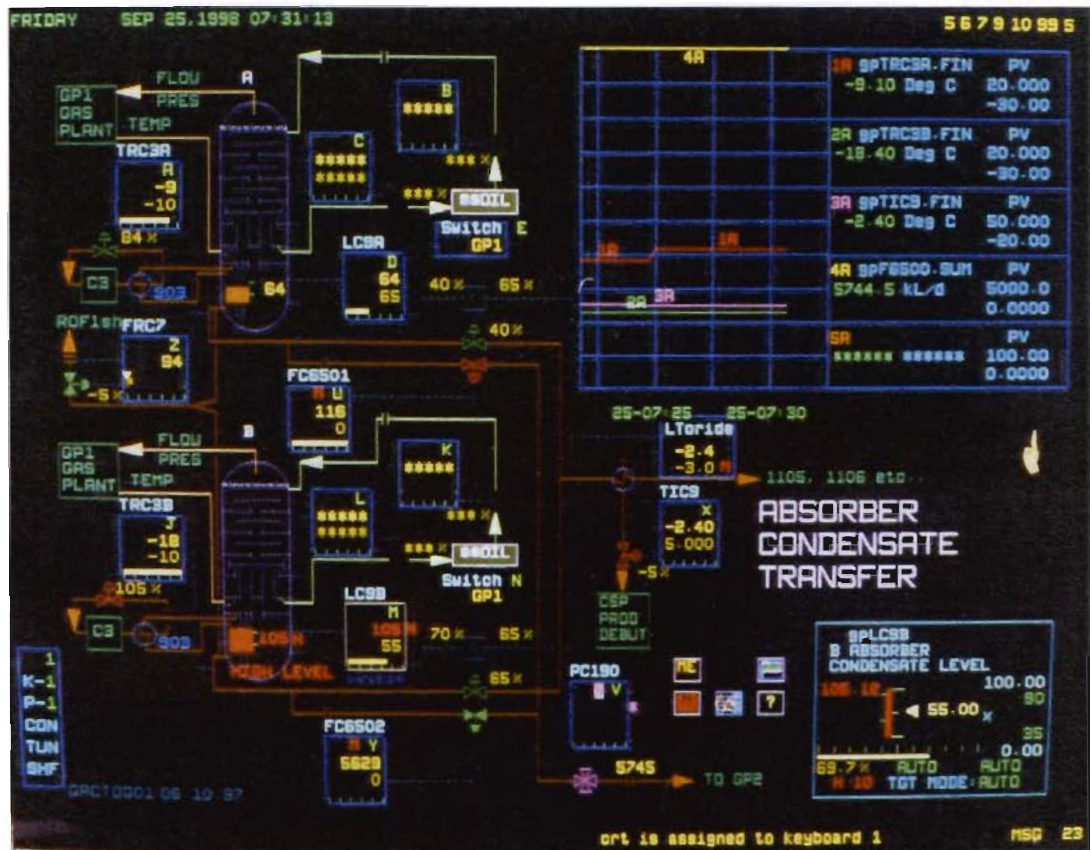


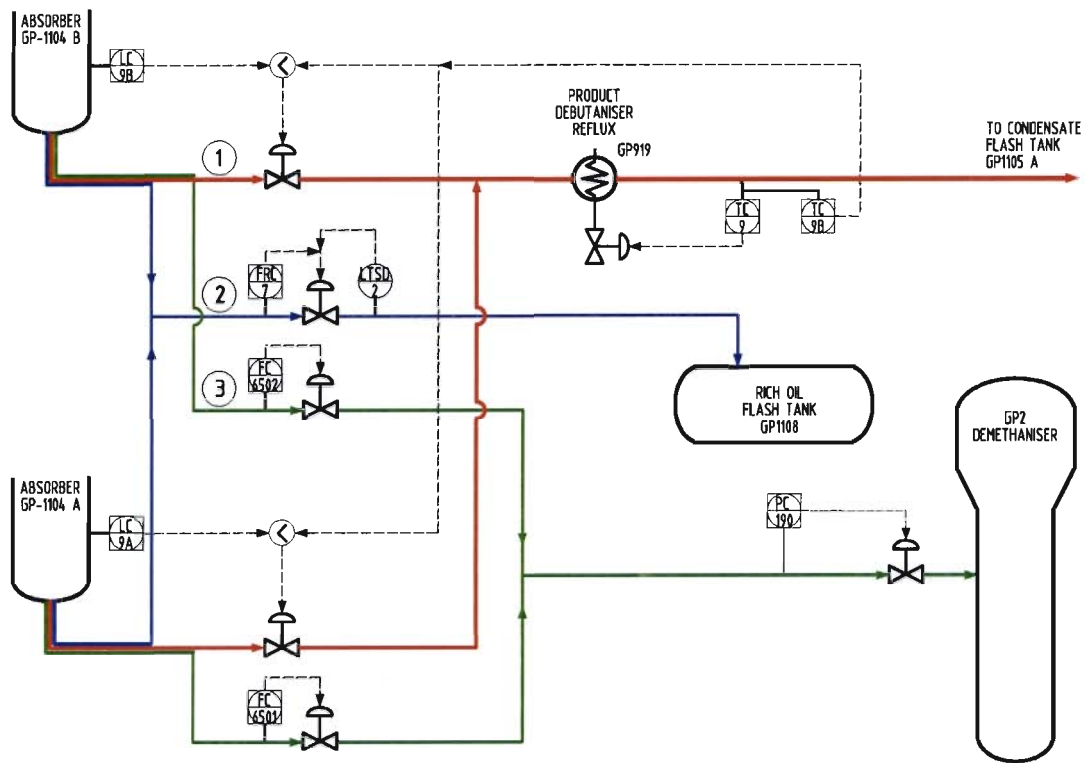
Figure 2.19 The Bailey screen for the GP1 absorbers

2.29 The Bailey system also recorded information historically. In addition to the Bailey system there was the Process Information Data Acquisition System (PIDAS). This system took the information recorded in the Bailey system and stored it in a compressed form in a computer server at Longford. This computer was connected to Esso's data communications network. The information was thus available to personnel both in Melbourne and Longford. In this way, PIDAS enabled the operation of the plant to be monitored remotely although, in the case of GP1, this was on a limited basis because only some 30% of the instrumentation was on the Bailey system and hence accessible on PIDAS. Otherwise reliance for operating history had to be placed on the ink charts. The only other chronological record of process conditions in GP1, apart from the log books of operators and supervisors, was provided by the Surveillance Information Database System (SIDS). This system required operators to walk around the plant recording information from local instruments on a Portable Data Terminal (PDT). Recordings were taken twice a shift (i.e. four times a day) for a set of specified process variables. Records from the PDT were then downloaded into a computer system, which was also linked to PIDAS.

#### ***The ROD/ROF Area Instrumentation***

2.30 Controls were in place throughout GP1 to regulate the levels, temperatures and pressures in various vessels. Among these was TRC3B, which has already been mentioned. It controlled the flow of warm propane to heat exchanger GP903B, which was associated with Absorber B. By this means TRC3B controlled the temperature in the bottom of Absorber B. There were also level controls for the condensate in the bottom of Absorber B and for the rich oil in Absorber B. They were known respectively as LC9B and LC8B.

2.31 Figure 2.20 shows the equipment that controlled the flow of condensate leaving Absorbers A and B. There were three alternate paths that the condensate could take for further processing. These paths, shown in Figure 2.20 as red, blue and green lines, delivered condensate to GP919, the Rich Oil Flash Tank and GP2 respectively.



**Figure 2.20 Control instrumentation for absorber bottoms condensate**

- 2.32 Before the condensate taking the red path from Absorber B reached the flash tank GP1105, it passed through a heat exchanger, GP919, where it was heated to a temperature of 1°C. However, if the temperature of the condensate passing through GP919 fell below a set temperature of -3°C, a temperature controller, TC9B, overrode the operation of the level controller, LC9B, reducing the flow of condensate through GP919, thus increasing the temperature of the condensate leaving that vessel. The consequence, however, was that, so long as the TC9B override was active, level control for condensate at the base of the absorber was lost and condensate could build up to a level well above the setpoint.
- 2.33 The condensate following the green path was transferred to GP2 via flow controllers FC6501 and FC6502. A pressure control valve, PC190, in GP2 was used to isolate this flow when condensate transfer was stopped. These valves were controlled by the Bailey system. Condensate was not following this path on the day of the accident.
- 2.34 The blue path for condensate delivered it to the Rich Oil Flash Tank, GP1108, and allowed cold condensate to be diverted temporarily to that vessel when transfer to GP2 was stopped. The flow was controlled by FRC7 and the Rich Oil Flash Tank was protected against excessively low temperatures by a low temperature shutdown switch LTSD2, which closed the FRC7 control valve at temperatures below -43°C. The Bailey system was designed to open FRC7 automatically when condensate transfer was terminated. Operators were

required to close the valve manually when the absorber's condensate temperature was back to normal (i.e. around -10°C). However in the months leading up to the accident on 25 September, condensate transfer was being controlled manually, hence this Bailey feature which opened FRC7 automatically was not being used.

- 2.35 The level of rich oil in the Rich Oil Flash Tank was also regulated by a control known as LRC1. This control operated a valve known as LCV1, which controlled the rate of discharge of warm rich oil into the ROD.
- 2.36 Mention has also been made of TRC4, which controlled the temperature in the bottom of the ROD by partially or totally bypassing lean oil around GP922 if necessary. This resulted in hotter lean oil flowing to the reboiler, GP905, in order to maintain the required temperature in the bottom of the ROD.
- 2.37 The level of oil in the Oil Saturator Tank was controlled by LRC2, which operated a control valve on the delivery side of the GP1201A, B and C booster pumps. In the event that LRC2 reduced the flow of lean oil below a preset rate, a low flow shutdown switch, LFSD8, was activated, shutting down the GP1201 pumps.
- 2.38 It was the GP1201 booster pumps that delivered the lean oil from GP905 through heat exchangers GP904, GP924, GP925 and GP930 to the Oil Saturator Tank. GP1204, which commenced the circulation of the lean oil from the ROF, had to be running before a GP1201 pump could be started. Otherwise a low flow shutdown switch, LFSD7, at the discharge of the GP1204 pumps would be activated to shut down the GP1201 and GP1204 pumps. From the Oil Saturator Tank another pump, GP1202, delivered lean oil to the absorbers and also a small stream of reflux back to the top of the ROD. This pump was protected from running dry by a low level shutdown switch, LLSD2, on the Oil Saturator Tank. There was also a low level alarm, LLA6, which gave early warning of a drop in level in the Oil Saturator Tank.

## ORGANISATION, SUPERVISION AND MANNING

### Management Structure

2.39 The part of Esso's management structure pertinent to this inquiry was that which was responsible for the production function at Longford and the services which supported that function. A diagram showing the sections of the management structure which directed or supported the Longford operation appears in Figure 2.21.

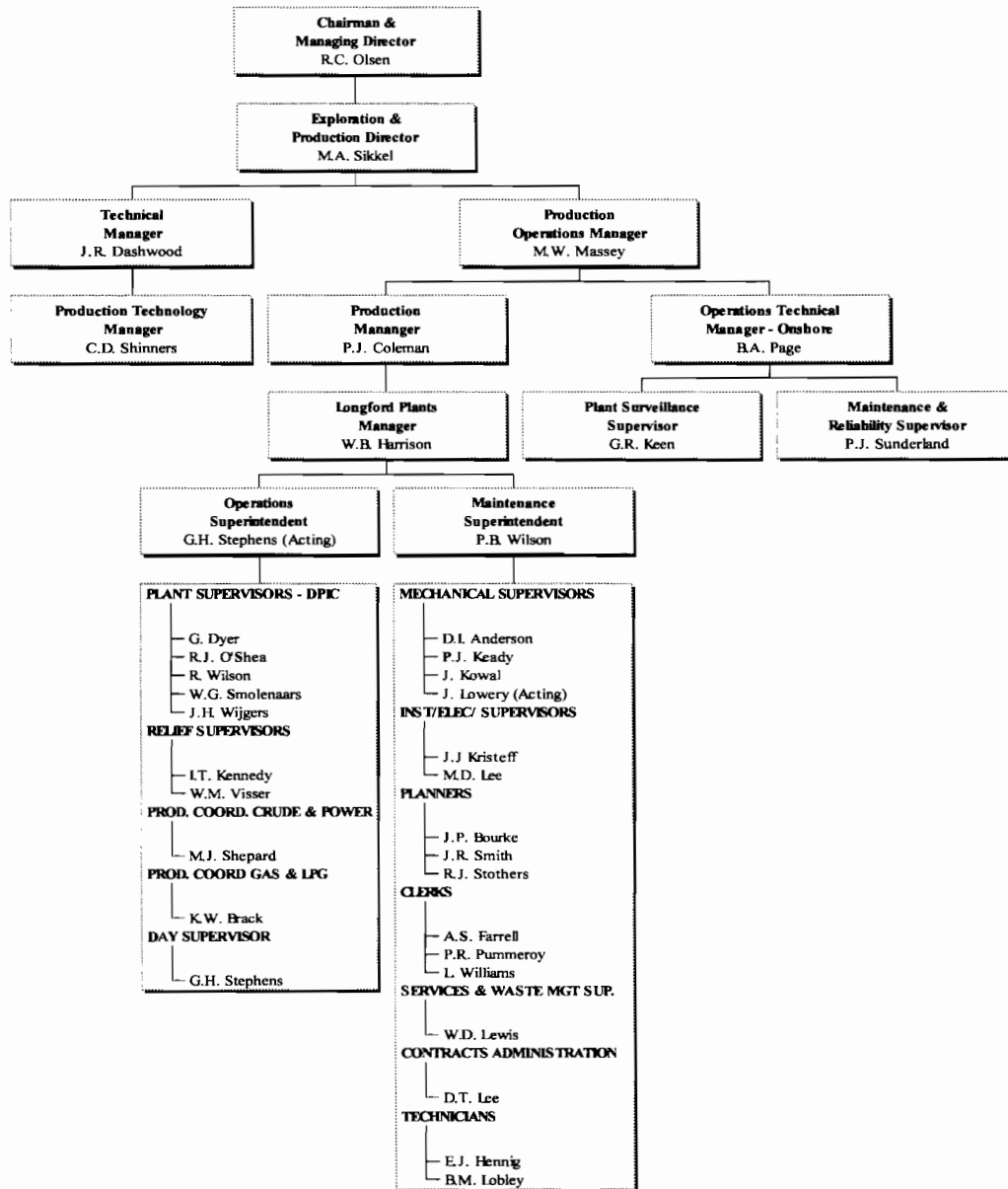


Figure 2.21 Line and support function management supervision for Longford operations

2.40 One feature of Esso's management structure was its depth of engineering expertise and operational experience. Esso was governed by a board of directors. They were Messrs Olsen, Sikkel, Heath and McElvy, under the chairmanship of Robert Olsen who is, and was

on 25 September 1998, also the managing director. Olsen is a mechanical engineer and has held numerous engineering and managerial positions in the Exxon organisation. At the time of the accident he had about 26 years of employment experience with Exxon and Esso. Olsen gave evidence.

- 2.41 The exploration and production director was Mark Sikkel to whom the production operations manager, Marty Massey, was responsible. John Dashwood, the technical manager, whose department provided services to the Operations Department, also responded to Sikkel. Sikkel gave evidence. He was the director ultimately responsible for operations at the Longford plants. Sikkel was an industrial engineer who was first employed by Exxon in 1975. Since then he has held senior production management positions. Sikkel held his position as exploration and production director from 1993 until 1999 when he became vice president, production, for the Exxon Company USA.
- 2.42 The operations manager, Peter Coleman, and the operations technical manager – onshore, Bruce Page, each responded to Massey. Coleman had responsibility for all offshore and onshore operations. Coleman trained as a civil engineer and has been employed by Esso since 1984. Between December 1993 and October 1994 he was operations superintendent at Longford. He took up his present position as operations manager in August 1996. Coleman gave evidence. Page's responsibilities covered plant surveillance, inspection engineering and maintenance and reliability, which were services provided to the Production Department. Gordon Keen was the supervising engineer for the Plant Surveillance Group and Phillip Sunderland was maintenance and reliability supervisor. Both Keen and Sunderland gave evidence.
- 2.43 The production technology manager, Christopher Shinnars, responded to Dashwood. Shinnars was responsible for the overall Risk Assessment and Management System. He was a civil engineer and had been employed by Esso since 1981 in engineering and managerial positions. Shinnars gave evidence.
- 2.44 The Longford plants were managed by Will Harrison who reported to Coleman. Harrison was a mechanical engineer who was first employed by Exxon in 1977. He had experience as an operations superintendent and site manager for Exxon before his appointment as Longford plants manager in June 1996. Harrison was responsible for overseeing all phases of Esso's operations at Longford. He gave evidence. On the day of the accident, Harrison was at Long Island Point participating in a work safety presentation.

### ***Longford Operations and Maintenance Organisation***

- 2.45 On 25 September 1998, Graeme Stephens was acting operations superintendent. The position of operations superintendent was vacant at the time. On the day of the accident, Stephens was on holidays and Mick Brack was appointed to act in Stephens' place. However, Brack was also absent due to illness. Stephens' usual position at Longford was day supervisor. The maintenance superintendent was Peter Wilson, who was killed when GP905 ruptured.
- 2.46 Brack's usual position was that of production co-ordinator, gas and LPG. This was one of two such positions answering to the operations superintendent, the other position being that of production co-ordinator, crude and power generation. This position was held by Mike Shepard. Shepard gave evidence. On 25 September, he was fulfilling the role of both co-ordinators. The acting operations superintendent (Brack) and the plants manager (Harrison) were absent at the time of the accident.
- 2.47 Reporting to the operations superintendent were seven plant supervisors. Five of these were deployed to supervise the five shifts operating the plant. The other two supervisors were available as relief personnel to cover sickness, holidays and long service leave.
- 2.48 Two day supervisors were also employed to assist with the supervision workload created by maintenance activities in the plant. The day supervisors normally worked a five day week and were not involved in the shift roster system.
- 2.49 The maintenance activities under the superintendence of Peter Wilson were supervised by three mechanical supervisors and two instrument/electrical supervisors. Three planners and three clerks planned the maintenance work and kept the necessary records.
- 2.50 Because of leave and sickness, there were several people in relief or acting positions on 25 September. Those involved in the lead up to the accident were Bill Visser who was relieving Glenn Dyer as supervisor for No.4 Shift, Ian Kennedy, who was acting as day supervisor in the absence of Stephens, John Lowery, who was acting mechanical supervisor, and Shepard who was filling both co-ordinator roles. Lowery was killed when GP905 ruptured. In the absence of the Longford plant manager, Peter Wilson was the most senior staff member on-site.

### ***Rosters at Longford***

- 2.51 The Longford process operations were continuous and therefore needed to be manned 24 hours per day every day of the year. This was achieved by five shift teams that rotated

on a roster which was made up of two twelve-hour shifts per day. Day shift commenced at 7.00 am and night shift at 7.00 pm. Night shift preceded day shift on a particular day. Thus night shift for 25 September commenced at 7.00 pm on 24 September and finished at 7.00 am on 25 September.

2.52 Shift teams consisted of either 13 or 14 men. There were 12 positions to be filled on each shift so that there was one spare man on some shifts and two on others. This provided nine spare men to cover holidays and sickness.

2.53 The roster for any one shift team consisted of a ten day cycle made up of two night shifts, one full day off, two day shifts then six days off. Two twelve-hour periods included in the time off were normal rest periods, which accounted for the complete cycle taking ten days rather than eleven. Ten training days per year on what would otherwise be days off made up the time needed to achieve a 35 hour week.

2.54 On 24 and 25 September, the two shifts on duty were Shift No. 5, supervised by Hans Wijgers and Shift No. 4, supervised by Visser. Wayne Olsson on Shift No. 5 was the night control room operator in GP1 who handed over to Jim Ward on Shift No. 4 at 7.00 am on 25 September.

2.55 The other shift operators who were involved in events on 25 September included Steve Bennett, Grant Cumming, David Delahunty, Martin Fahy, Bill Hector, Kurt Mielke, Robert Miller, Ron Rawson and Steve Young.

2.56 Recently qualified operators Heath Brew, Greg Foster and John Wheeler, and trainee operator Marty Jackson were also involved on 25 September. Andy Noble, the training supervisor, was involved in the rescue operations after the rupture of GP905.

### ***Maintenance Work Force***

2.57 The maintenance work force normally worked a five day week and there were no maintenance personnel on shift. Failure of important process equipment occurring outside normal working hours required the appropriate maintenance personnel to be called in.

2.58 The regular maintenance work force at Longford at the time of the accident consisted of 58 persons of whom three were contractors and 44 were qualified tradesman or technicians. Contract labour was used to supplement this workforce from time to time.

2.59 In 1992, the maintenance group at Longford was re-organised to place more emphasis on planning. An additional planning position was added, and more experienced operations and



maintenance personnel were relocated to these positions. Then, in 1993, as part of the implementation of the structural efficiency programme, the competencies required by maintenance technicians at Longford were evaluated, and training and assessment programmes implemented, to ensure that these competencies were met. The intention was to reduce the reliance by maintenance technicians on their supervisors for technical support (i.e. one job did not require two people to the extent previously). Four levels of technicians were provided for under the new programme: base technician, technician 1, technician 2 and senior technician. The senior technician position required higher levels of technical competency than had previously been required by Esso at Longford.

- 2.60 Following these changes, the number of supervisors and associated staff at the Longford plant fell from 25 in 1993 to 17 in 1998. Over the same period, there was also a reduction in the number of maintenance staff from 67 to 58.
- 2.61 By the time of the accident, there were senior technicians engaged at Longford in the mechanical, electrical and instrumentation disciplines. These technicians played an important role in the implementation of safety and reliability improvements.

#### ***The Co-ordination of Production and Maintenance Activities***

- 2.62 Maintenance work order requests could be originated by any Esso person. The originator allocated a priority according to an accepted system designed to ensure that important work was done first. This allocated priority was reviewed by a supervisor. All safety work requests were reviewed at the morning production meeting and after discussion the original priority could be changed. The work requests were then scheduled by planners and the draft schedule for the following day was reviewed at the afternoon co-ordination meeting. The work requests for the following day were then forwarded to the night shift supervisor for the preparation of permits and equipment to enable the work to proceed. Before the work commenced on the following day these permits required authorisation by the day shift supervisor for hot work or by the appropriate operations technician for cold work.
- 2.63 The morning production meeting was attended by the plant manager, the superintendents, co-ordinators and supervisors. The afternoon co-ordination meetings were chaired by the maintenance superintendent and attended by maintenance supervisors, planners and production co-ordinators.

#### ***Shift Handover and Tool box Meetings***

- 2.64 With the aim of providing an effective handover procedure upon change of shift, the Longford Work Management Manual (LWMM) laid down requirements for the verbal and

written transfer between operators of information on the operation of the plant during the previous shift and the process conditions prevailing at the time of the handover. These are discussed further in Chapter 13.

- 2.65 Commencing at 7.15 am on day shifts and about 9.30 pm on night shifts, toolbox meetings were held in the two plant control rooms. These were conducted by the shift supervisors and were attended by all the operators and trainees working in each area. These meetings were used to inform operators of the maintenance work planned in their area, of the Gascor sales forecasts for the day and of accidents or process problems which had occurred on previous shifts. A safety message was also included. On day shift, the work permits for the jobs planned for that day were handed out to the appropriate operators.
- 2.66 Toolbox meetings for maintenance personnel were conducted in the workshop at 7.30 am. First jobs for the day were handed out, and safety requirements and any special instructions were given. Toolbox meetings ordinarily took 15 to 20 minutes.

### ***Shift Supervisors' Duties and Supervision***

- 2.67 Two structural changes to operations management occurred at Longford which were relevant to the matters under investigation. These changes were the relocation of engineers from Longford to Melbourne and the redefinition of the role and responsibilities of supervisors and operators.
- 2.68 The circumstances surrounding the relocation of engineers from Sale to Melbourne, which are further described in Chapter 13, occurred in 1992. Coleman said that the engineers at Longford typically performed two roles. The first was that of surveillance which included monitoring the process to ensure that operations were undertaken within safe operating limits to maximise recovery. The second was a "project role", in which engineers were responsible for the implementation of projects.
- 2.69 Coleman explained the relocation of engineers by suggesting that they were not typically involved with daily process related problems "but rather were called in for equipment design/recovery projects and process optimization tasks". He said that "the introduction of PIDAS has provided engineering personnel with current and historical information about the process since moving to Melbourne. In addition, Esso retained its fixed wing aircraft service to ensure that its engineers could be on-site if required." Coleman went on to say that other facilities operated efficiently and safely without ever having engineers located in close proximity. He saw no relationship between the accident and the relocation of engineers to Melbourne and said that in any event Harrison was an engineer. Sikkell said

that in his experience it was unusual to have engineers on-site at gas plants and treating facilities. He said that the operations personnel of a gas plant are in the best position to respond to plant-operational upsets. Nevertheless plant surveillance, further discussed in Chapter 13, assumed a new and significantly different function at Longford as a result of the change.

- 2.70 The second structural change affecting Longford was that which occurred in mid-1993 involving the redefinition of the responsibility of operators and supervisors. This change is also discussed in Chapter 13 in the context of Esso's management of change policies. Coleman said that in mid-1993 there was a change in the philosophy behind manning and in the operations organisation structure arising out of an agreement between the unions representing operators and management. The restructuring involved operators assuming greater responsibility for the operations of the plant thus relieving the supervisors of the "leading hand" role. It was at this time and in these circumstances that operators elected to become control panel operators or machinery operators acknowledging a certain degree of specialisation between the two.
- 2.71 The restructuring also caused consequential changes in the number of supervisors present during shifts. These numbers were reduced and, in addition, the supervisors' roles changed in that they were not expected to be in the plants on a continuous basis. The supervisors "were released from acting as backup operations technicians and allowed to assume a truly supervisory role" with the support of new technology. Coleman said that the restructuring process reflected the desire of Esso, with the support of its employees, to increase the degree of ownership of the processes in the Longford plants at an operations technician level. He acknowledged that the operating technicians assumed a greater responsibility for the day to day operation of the plant, including troubleshooting to overcome process irregularities, but they were remunerated accordingly.
- 2.72 Evidence from Visser indicated that the primary role of the shift supervisors had become largely administrative, since, by agreement with the four unions represented at Longford, the responsibility for effective plant operation had been transferred to the operators. Even if a shift supervisor had no significant administrative responsibilities, it would have been difficult for one person to provide effective process oversight on a plant as large and complex as Longford.
- 2.73 On day shift on week days there were other experienced supervisors available on-site who could be called on to assist with process problems if required, but during the remaining 130 hours or so each week this was not the case.

- 2.74 A further organisational change occurred in mid-1996, pursuant to an enterprise bargaining agreement. The number of operating areas at the Longford plants was reduced from 14 to 12 and the offshore control room was consolidated into the GP3 control panel position. Coleman observed that the object of these changes was to operate the plant safely, taking advantage of efficiencies provided by the day crew and the increased competencies of the operators. There were other consequences flowing from the enterprise bargain described by Coleman. In the second quarter of 1997 a further restructuring occurred, designed to take full account of the efficiencies gained through the introduction of new systems, such as OIMS, and new technology such as PIDAS and the LAN.
- 2.75 The relevance of these structural changes to the accident is discussed in Chapter 13.





# Chapter 3

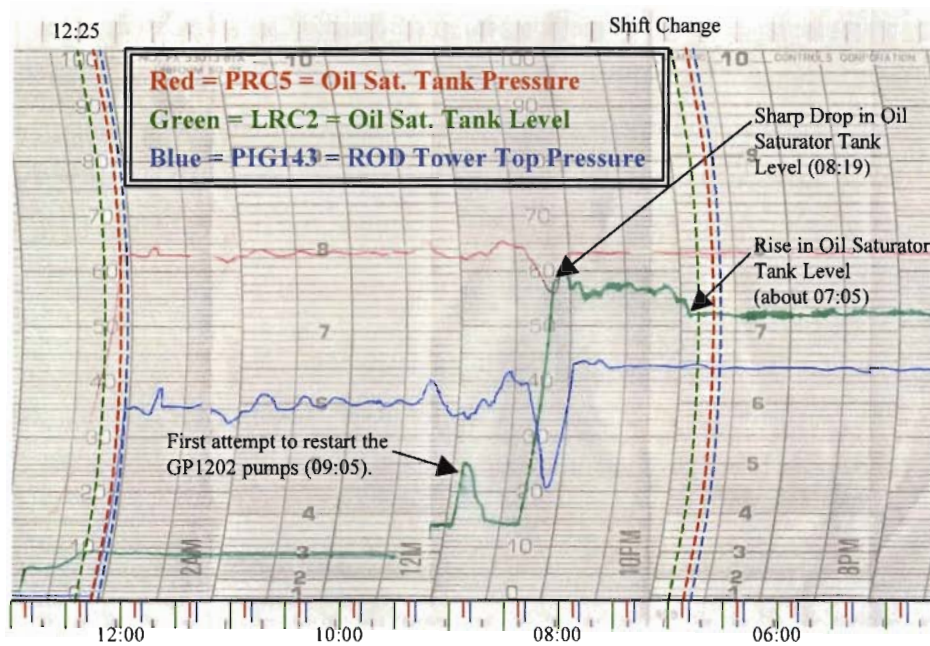
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## THE ACCIDENT

### *INTRODUCTION TO THE EVENTS OF 25 SEPTEMBER*

- 3.1 It is now possible to describe briefly the events which preceded the explosion and fire on 25 September 1998.
- 3.2 On the night shift that preceded the day shift on 25 September, there was a strong flow of liquids into the slugcatchers. The slugcatcher liquids were processed in the Crude De-ethaniser GP1106B and the Feed Liquid Stripper, GT1102, in GP2. The lighter components were fed back to the GP1 gas inlet via compressors known as the KVR compressors. This gas (together with gas from the CSP) was referred to as KVR gas. The large volume of liquids being processed from the slugcatchers indicated that the volume of KVR gas flowing to the absorbers would be higher than normal, resulting in a feed that was rich in heavy hydrocarbons. This would have produced a large quantity of condensate as the gas passed through GP901 and GP902. This condensate would then have been separated in the bottom section of the absorbers.
- 3.3 It is clear that there was a build up in the level of condensate in Absorber B during the night shift. As there was no condensate transfer to GP2 taking place, the only available routes for condensate from Absorber B were the line passing through GP919 to the Condensate Flash Tank or, if condensate levels became high enough, the rich oil stream to the Rich Oil Flash Tank. The volume of condensate leaving the absorbers was large enough and cold enough to cause TC9B to override LC9B and significantly reduce the flow of condensate through GP919. The result was a build-up in the level of condensate in Absorber B. Absorber A was not similarly affected as it was fed with leaner gas containing less inlet and KVR gas. Also, its reboiler, GP903A, was functioning automatically, enabling it to effect temperature control of condensate so as to maintain a higher absorber bottom temperature. As a consequence, it was producing less condensate and TC9B did not override the level controller, LC9A.
- 3.4 The level of condensate in Absorber B rose to a point where it was not possible to measure it by the available instrumentation. In all probability, the level of condensate in Absorber B was such that it carried up into the rich oil section of the absorber. That meant that

condensate entered the rich oil stream causing that stream to flash more than usual on its way to the Rich Oil Flash Tank, GP1108, and to drop in temperature. A number of unusual events in the ROD/ROF area occurred after the condensate level in Absorber B became high. These were directly related to the lower than normal temperature in GP1108, and the lighter than normal composition of its contents. The most probable reasons for these events occurring are discussed later in Chapter 5. The first of these events was a rise in the level of the Oil Saturator Tank GP1110, which can be seen on the relevant strip chart (see Figure 3.1) from just after 7.00 am to about 8.19 am when the level fell sharply. The additional liquid flow causing this rise in level would appear to have come through the pipe from the top of the ROD tower, which was the path normally taken by the methane used to presaturate the lean oil flowing to the Oil Saturator Tank. The rise in level demonstrates that there was an upset in the ROD at this time. (This is discussed in more detail in Chapter 5.)



**Figure 3.1 Strip chart showing the rise and sharp fall in the LRC2 Oil Saturator Tank level**

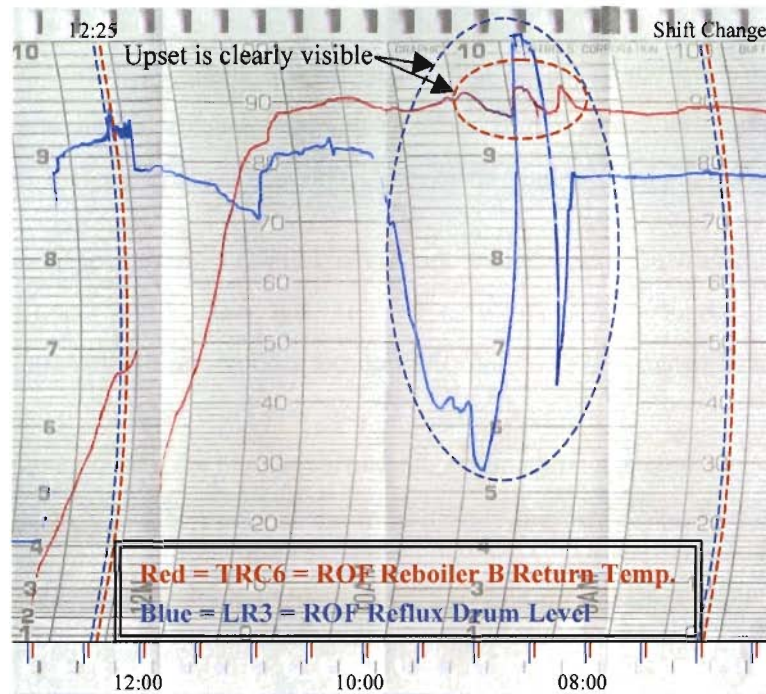
3.5 A consequence of the rise in the level of the Oil Saturator Tank was that LRC2 closed the valve regulating the flow from the GP1201 pumps. This reduction in flow would have caused LFSD8 to shut down the GP1201 pumps. With the shutdown of the GP1201 pumps, the level in the Oil Saturator Tank would have fallen rapidly as the GP1202 pump delivered the contents to the absorbers and ROD reflux. GP1202 was protected against running dry by a shutdown switch that was triggered by a low level in the Oil Saturator Tank. Following the fall in the level of the Oil Saturator Tank, the strip chart shows that the level steadied out

when the switch operated to shut down GP1202. Lean oil circulation stopped when the GP1202 pump shut down.

- 3.6 Following the cessation of lean oil circulation, gas continued to enter GP1 both from offshore and via the KVR compressors. Some 40% of the continuing incoming gas was rich KVR gas from the CSP and Condensate De-ethaniser which produced higher amounts of condensate in the absorbers than gas from offshore. However, the offshore gas was probably also quite rich in condensable components as preference was given to the production of gas from the Marlin field. This was the richest of the three main gas fields.
- 3.7 As the inflow of gas continued, the production of condensate also continued. With the high level of condensate in Absorber B, it is likely that a significant quantity of condensate continued to be carried up into the rich oil section and to flow from there to the Rich Oil Flash Tank. Within five minutes of loss of lean oil circulation, the flow would have ceased to be a mixture of rich oil and condensate and would have become pure condensate.
- 3.8 Had the GP1201 and GP1202 pumps been restarted within a reasonable time after their shut down, the subsequent failure of GP905 would have been averted. Whatever efforts were made to restart the GP1201 pumps, they were unsuccessful, notwithstanding that the pumps could normally be turned over by simply holding down the starter button. This would have induced a flow, provided that the pumps were not vapour-locked. It was also possible to override the low flow shutdown switch by placing the pumps in test mode. This involved using a switch located in the switch room some distance away from the pump. Both of the relevant shift operators say that they were not aware of how the low flow shutdown could be bypassed. Once the GP1201 pumps ceased to operate, the GP1204 pumps, which delivered hot lean oil from the ROF, were confined to recirculating lean oil through the fired reboiler, GP501. Later in the morning at about 11.10 am GP501 was manually shut down, together with the GP1204 pumps.
- 3.9 Following the cessation of lean oil flow, the condensate flowing from the absorbers through the rich oil system was flashing at lower and lower temperatures with the result that there was a drop in temperature in the Rich Oil Flash Tank and the ROD system. Indeed, the absence of any lean oil flow to the heat exchangers GP904, GP924, GP925 and GP930 meant that the condensate flowing through the rich oil system was not warmed before it reached the ROD, GP905 and GP922. Simulations indicate that the temperature reached as low as -48°C in this section of the plant. This cold flow caused an upset on entering the ROF. The ROF ceased to boil and there was a much reduced flow of vapour from the top of the ROF. This upset is clearly visible on the ROF strip charts. This in turn caused a



reduction in level in the ROF Reflux Accumulator so that the panel operator thought that the reflux pump, GP1203, had shut down. (See Figure 3.2). That pump delivered reflux back to the top of the ROF. Attention was diverted from the attempts to restart the GP1201 pumps when the area operator was asked to check the situation of GP1203.



*Figure 3.2 ROF strip chart showing upset*

- 3.10 Because GP922 became cold in the manner described, its flanges became distorted causing leakage at each end. This was compounded by the effect on the lean oil flow of broken tubes subsequently found in the exchanger.
- 3.11 The temperature and condensate carryover problems were exacerbated by the failure, in the absence of automatic temperature control by TRC3B, to manipulate effectively the bypass around the temperature control valve. TRC3B had been malfunctioning for at least ten days, having failed in the closed position due to a faulty positioner. During the morning of 25 September 1998, sporadic attempts were made to control the temperature in Absorber B by operating the bypass, but the condensate temperatures were consistently below the setpoint of  $-10^{\circ}\text{C}$ , reaching  $-25^{\circ}\text{C}$  at one stage.
- 3.12 Both GP905 and GP922 exhibited signs of extreme coldness by the formation of ice on the uninsulated parts of their exteriors and on the pipework to and from them. A decision was made to shut down GP1 shortly after 11.00 am. This involved the transfer to GP2 of gas coming from the CSP through the KVR compressors and stopping the inflow of offshore gas.

- 3.13 Subsequently, a decision was made to recommence the flow of warm lean oil by restarting the GP1201 and GP1204 pumps. This was done in order to warm GP922 in the belief that it might solve the problem of the leaks. The fired reboiler associated with the ROF had been shut down by this time and it was assumed that when the pumps were restarted the lean oil flowing from GP1204 would be cooler than its normal temperature of 285°C. The pumps were restarted and some lean oil reached GP905, creating a thermal shock and brittle fracture of the reboiler.

### ***TRC3B AND THE CONTROL OF ABSORBER B***

- 3.14 The TRC3B valve had been giving trouble for some time before the accident on 25 September. It should be recalled that TRC3B was a control system designed to regulate the temperature of condensate in the bottom of Absorber B (see Chapter 2). Work was undertaken on TRC3B pursuant to a work order request dated 17 March 1998. On that occasion the TRC3B valve was not closing fully. One of the block valves was also not closing fully. Repairs were effected by injecting methanol into the process, apparently in the belief that a hydrate was causing the problem. Whatever the cause, the injection of methanol appeared solve the problem.
- 3.15 On 11 September 1998, the day shift experienced cold temperatures in Absorber B, notwithstanding that the control panel indicated that that the TRC3B valve was fully open. PIDAS records show that the valve was not responding to controller output signals. The bypass was operated to bring the temperature back into normal range. The bypass valve was not at that stage tagged to indicate any departure from normal operation.
- 3.16 On 12 September 1998, Brew made a work order request with respect to TRC3B. The complaint was that the TRC3B control valve would not operate. The request was allocated a priority two, which meant the work should be completed in 15 days. An instrument technician, who was working on a job adjacent to TRC3B on 15 September, was approached by an operator to look at the valve. He repaired the feedback arm, which had come adrift from the valve positioner. Nevertheless the problem remained in that the valve opened only slightly in response to an output signal. Apparently methanol was again used in an attempt to cure the defect, but without success this time. The technician suggested to the maintenance supervisor, Mark Lee, that there was an internal problem with the valve, which could only be corrected by dismantling it. In fact, the valve had failed in the closed position but Lee thought that it was merely sticking. Lee scheduled the repair of the valve for 1 October 1998 although, depending on the workload, it could have been repaired before that. However, the events of 25 September 1998 supervened. Subsequent examination of

the TRC3B control valve found that the diaphragm of the relay in the positioner was ruptured.

- 3.17 On 14 September the night shift again experienced low temperatures in Absorber B. The area operator, Peter Burley, observed that the bypass to TRC3B was still open, whereas the bypass to TRC3A was fully closed. Wijgers, the shift supervisor, instructed him to place TRC3B on the Temporary Defeats Board, which he did. The notice placed on the board said “TRC3B U/S. Running on bypass valve” and “Valve seized up coupla days!” [sic].
- 3.18 The Temporary Defeats Board was intended to indicate which protective equipment, such as fire pumps, heaters and some control valves, was not functioning properly. Whether TRC3B should have been considered to be protective equipment is a question that was not raised at the time. At the end of that night shift on 15 September the TRC3B bypass was still open.
- 3.19 The shift supervisor on the night shift commencing on 22 September 1998, Ray Wilson, says that following a report of traces of lean oil carryover from Absorber B to fuel gas, he asked the ROD/ROF operator, Norm Watts, to close the TRC3B bypass. Watts did so, being under the impression that he was making adjustments to improve recoveries. Despite the fact that TRC3B was the subject of a work order request and had been placed on the Temporary Defeats Board, neither Wilson nor Watts appear to have known that it had failed.
- 3.20 During the day shift on 23 September 1988, Wilson was again the shift supervisor, Hogan was the GP1 panel operator and Watts was again the ROD/ROF area operator. They discovered that the TRC3B bypass had been opened again. Wilson told Watts to close the bypass, which he did during the afternoon. Watts, although not requested by Wilson to do so, placed a lock and chain on the bypass valve and tagged it with a tag saying “Do not open this bypass per Ray Wilson” or words to that effect. Wilson says that he was unaware of any history of TRC3B’s failure to function and for that reason did not submit a work order request.
- 3.21 On the handover from the day shift on 24 September to the night shift, the outgoing control panel operator, Hogan, briefed the incoming control panel operator, Olsson, about the high level of condensate in the slugcatchers. Hogan also says that he briefed Olsson about a drop in temperature in Absorber B to  $-40^{\circ}\text{C}$  which had occurred at about 4.30 pm. Hogan says that he then ordered Watts to open the TRC3B bypass valve. Watts, he says, did so, thereby returning the temperature to its normal range. However, Olsson has no recollection of having been told this and the process upset described by Hogan is quite inconsistent with all the other evidence, including PIDAS data.

- 3.22 At the start of his shift, Olsson said he noticed that the temperature at the bottom of Absorber B was too low. At a shift meeting at about 9.30 pm the status of TRC3B was discussed. After the meeting, Olsson spoke to the shift supervisor, Wijgers, about the tagging of the bypass. They were aware that TRC3B appeared on the Temporary Defeats Board and that the control valve had been malfunctioning for some time. Olsson and Wijgers looked in the supervisors' log book to find some reason for the bypass valve being tagged but found no reference to it. It was normal practice to give some explanation in the log book if there was a specific instruction not to operate something.
- 3.23 A decision was made by Olsson and Wijgers to remove the lock and tag and open the TRC3B bypass to bring the temperature of Absorber B within normal operating range. The bypass valve was given three turns at about 11.00 pm and the temperature in Absorber B returned to a normal level within 15 minutes. At the end of the night shift Olsson asked his area operator Noel Robinson to open the bypass further when he next went past the valve. It is unclear from the evidence whether the valve was further opened by Robinson.
- 3.24 On the handover from the night shift to the day shift on 25 September 1998, Olsson told the incoming control panel operator, Ward, of the decision made during the night shift to open the TRC3B bypass in order to regulate the temperature in Absorber B. Olsson also told Ward of high levels of condensate in the slugcatchers overnight and of the low ambient temperatures resulting in high gas demands, but said that the plant was now operating normally. No reference was made to the level of condensate in Absorber B. On the same handover, the outgoing area operator, Robinson, told the incoming area operator, Rawson, of the opening and closing of the TRC3B bypass valve, saying that there was a tug of war between the two supervisors, Wilson and Wijgers. Wijgers wanted it open and Wilson wanted it closed.
- 3.25 At the toolbox meeting in GP1 on 25 September 1998, no matter of significance was raised concerning the operation of the plant. At about 7.20 am, Ward, said that he noticed that the temperature in Absorber B was within normal range at -13°C. PIDAS data shows that it was really at -18°C. Ward asked Visser, whether he could have the TRC3B bypass closed. Notwithstanding the conversation with Olsson at the handover, Ward says that he assumed that the bypass valve had been chained and tagged in order to test the operation of TRC3B. Visser authorised Ward to operate the bypass valve as he saw fit. At 7.30 am Ward directed the area operator, Rawson, to close the TRC3B bypass. At the time of giving this direction, he was unaware that the level of condensate at the base of Absorber B was so high as to be off-scale.

### ***THE LEAK FROM GP922 AND THE LOSS OF LEAN OIL CIRCULATION***

- 3.26 At about 7.30 am the area operator, Rawson, closed the bypass on TRC3B on Ward's instructions. Within half an hour the temperature in Absorber B had fallen from -18°C to -26°C. At about 8.22 am, Ward instructed Rawson to open the bypass valve again. Rawson opened the valve to about 20% of its capacity.
- 3.27 At about 8.30 am, Rawson noticed that there was a leak at the western end of GP922. There was a drip tray under the leak. Rawson says that he would have informed Visser, and Ward's recollection is that Visser and Rawson left the control room to inspect the leak at about this time. As will become apparent, Visser recollected a different inspection with Rawson or, at least, an inspection at a different time.
- 3.28 There was a radio system operating at Longford to enable personnel to communicate with one another. The communications were recorded together with the time at which they were made. The times were recorded on a 24-hour basis and it is convenient to adhere to that method when referring to them.
- 3.29 A radio transcript of the communications on 25 September reveals that at 8:29:43 Ward contacted Rawson by radio and told him that the GP1201 lean oil booster pumps had shut down. He asked Rawson to restart them. The call was apparently in response to an alarm in the control room. Rawson said that he attempted to start the GP1201 pumps but was unable to get them running. He returned to the control room and asked Ward if they had shut down because of a low level in the Oil Saturator Tank, GP1110. A check revealed that there was a low level in this tank and as a consequence, the GP1202 pump had shut down as well. Rawson then left the control room and attempted to restart the GP1201 and GP1202 pumps by pressing the starter buttons, but they would not start. Rawson said that all three GP1201 pumps failed to respond when he depressed the start buttons installed at the pumps.
- 3.30 At 8:38:14 Ward contacted Rawson by radio in response to an alarm indicating the shutdown of the ROF reflux pumps, GP1203A and B, as a consequence of a low level in the reflux drum. Rawson went to these pumps and found that one pump was still running and achieving a small flow so he returned to continue his efforts to restart the GP1201 and GP1202 pumps. At this time he noticed that GP922 had icing on the west end and GP905 had icing on the east end. He also noticed that the ROD had icing on the outlet to GP905 and GP904 and that the suction and discharge lines on the "very north pump" of the three GP1201 pumps (the GP1201A pump) had icing on them as well.

- 3.31 At 9:05:34 Ward told Rawson on the radio that GP1202 had actually restarted for a while, but that it had sucked the level straight out of the Oil Saturator Tank and that the level would have to be built up again before it could be restarted. Rawson said that he had only got one GP1202 pump started but that he could not get the GP1201 pumps started at all. Rawson asked Ward what the level in the ROD was. He could see ice on the pipe coming out of the bottom of the ROD to the GP922 exchanger and concluded that it had no level. Ward replied that he could find no indication of a level in the control room. The only level indicator was out in the field on the ROD itself. Rawson told Ward that he would inspect the level visually. He attempted to do so through a sight glass but could not see any level.
- 3.32 At 9:16:02 Ward sought extra manpower from Visser, who was at the daily production meeting. Ward was told that the day crew were all on training, but that they would be back shortly. In the course of this radio conversation Ward did not tell Visser that the GP1201 and GP1202 pumps had shut down, nor did he tell Visser of the difficulties being experienced in restarting them.
- 3.33 By this time, a gas-fired reboiler, GP502B, which was associated with the Crude De-ethaniser tower, had also shut down. This appears to have been a matter of immediate concern to Ward. At about 9.20 am Rawson went to GP502B, but did not relight it. A sufficient level in the tower for the pumps to operate was necessary before the relighting of GP502B could take place. At 9:25:53 Rawson asked Ward whether there was enough level in the Crude De-ethaniser tower to start the pumps which fed the GP502 reboilers. Rawson told Ward that he had started the pumps, but they had not continued to operate. At 9:26:41 Ward informed Rawson that the level had dropped out of the Crude De-ethaniser tower and that the relighting of GP502B would have to wait until it returned.
- 3.34 By 9:28:38, Rawson was at PRC10 which controlled the pressure at the top of the Product Debutaniser tower in the CSP. He was there in response to a request from Hector at 9:26:48 to open the bypasses on PRC10. This request was apparently in response to an alarm on the CSP control panel. Rawson opened the PRC10 bypasses and, at about that time, asked Ward whether there was sufficient level in the Crude De-ethaniser tower to start the pumps. He told Ward that the pumps were not running but that they were still in test mode and that he would go and start them up. Rawson says that at about this time he got one GP1201 pump running and then managed to get one GP1202 pump running. Charts show no indication of a GP1201 pump running but there are two spikes indicating two attempts to start the GP1202 pumps.

- 3.35 Rawson then went to LC8B, which controlled the rich oil level in Absorber B, to look at those levels. He thought that the icing on GP922 and GP905 may have indicated low levels there. The visual check was again through a sight glass and a level was hard to see. Rawson was not able to determine whether there was a level or not. He asked Ward's permission to open the bypass valve to enable him to hear or feel any liquid or gas passing through. Ward gave permission and Rawson concluded that there was liquid flowing through. While Rawson was at LC8B, Ward contacted him and told him that the Longford Liquid Recovery Plant (LLR) had shut down. Ward thought that Rawson was at GP502B, which was close to the LLR, so that it would have been convenient for him to have restarted it. Rawson informed Ward that he was at LC8B and Ward said that as soon as a day crew was available he would get them to restart the LLR.
- 3.36 The time at which Visser first learnt of the loss of lean oil circulation was unclear from the evidence. According to Rawson, Visser was with Rawson when Rawson inspected the sight glass on the ROD at 9:06:29 to ascertain if there was any liquid level at its base. Visser, on the other hand, said that he did not learn of the leak from GP922, or the loss of lean oil circulation, until after the daily production meeting when he went across to GP1. He said that he left the production meeting at about 9.30 am and returned to the control room. On his return, he said he noticed on the control panel, that there was a high level of condensate in Absorber B. He suspected that TC9B was overriding LC9, allowing the level of condensate in Absorber B to rise. He left the control room to inspect the level visually but could see nothing unusual and returned to the control room. On his way back he noticed that there was frosting on the pipework to and from the ROD and thought that the high level of condensate in Absorber B might be overflowing into the rich oil tray and into the rich oil system. He formed the view that the TRC3B bypass should be opened, but, on going out into the field again, observed that it was already open. He says that he opened it two more turns and, on returning to the control room, pointed out that there was a leak from GP922. It is then, according to Visser, that he and Rawson inspected GP922 and observed ice on the pipework from the ROD to GP922.
- 3.37 On balance, it is unlikely that Visser was aware of the shutdown of the GP1201 pumps or the loss of lean oil circulation before the conclusion of the daily production meeting, when he returned to the GP1 control room.
- 3.38 At 9:58:13 Rawson informed Ward that he had opened the LC9B bypass. LC9B controlled the level of condensate in Absorber B. Rawson did this upon the instruction of Visser, who was with him at the time.

3.39 At 10:09:50 Visser called Rawson from the control room and told him that a level was starting to come back in the flash tank. This was clarified by Visser as the Condensate Flash Tank, GP1105A. Rawson understood this to mean the Rich Oil Flash Tank GP1108. Rawson replied that he might even want to crack the bypass a bit more around LC9B. Visser agreed.

3.40 Rawson then noticed that the GP1202 pump which he had started was hot and billowing smoke. He tried to stop it by pressing the stop button, but it would not shut down. Rawson asked Visser to come and look at the pump. Visser also tried unsuccessfully to stop it by pressing the stop button. Visser says that he then went to the switch building and tripped the breaker there, which stopped the pump. At 10:23:39 Rawson asked Visser whether he had tripped GP1202 B and Visser told him that he had.

### ***THE SHUTDOWN OF GP1 AND SUBSEQUENT RESTART OF THE LEAN OIL PUMPS***

3.41 Visser returned to the control room and spoke to Jim Kristeff, an electrical supervisor, about the GP1202 pump. Shortly afterwards Rawson informed Visser that the leak from GP922 was getting worse. Both Rawson and Visser went out to look at GP922 and observed that both ends of the vessel were leaking. It was then that Visser decided to shut down GP1. This meant not only stopping the flow of inlet gas from offshore but also transferring to GP2 the gas coming from the CSP via the KVR compressors. The transfer involved opening and closing valves in GP1 and GP2 and usually took around half an hour to complete.

3.42 At 10:52:27 Visser contacted the control panel operator in GP2 and asked him to prepare the plant to receive the KVR gas. At 11:08:30, Visser informed Hector, who was answering on behalf of Ward, that he was going to shut down the ROF fired reboilers, GP501A and B. He then manually shut down the GP1204 pumps from the control room. Visser then went out and isolated GP922 from the ROD by closing one of the two LC10 block valves. At 11:11:21, Ward asked Rawson to block in the fuel gas block valves for the fired reboilers as a safety precaution. Rawson did not do this straight away, attending first to the transfer of the KVR gas to GP2.

3.43 Miller, the area operator for the KVRs, also attended to the redirection of the KVR gas to GP2. It was not until about 11.20 am that the transfer was completed. At 11:13:40 Hector observed that the GP1/CSP electrical tie had been lost due to the shutdown of GP1. Miller, with Foster, went to the old generator building and restored the tie.





- 3.44 After the lean oil system and the inlet gas had been stopped, but before the steps necessary for the transfer of KVR gas to GP2 had been completed, Visser went to Kennedy's office to seek assistance. He and Kennedy made their way to GP1 via Peter Wilson's office. Visser told Wilson what was going on. Visser and Kennedy proceeded to GP922. When they arrived they observed a pool of liquid under and around the vessel and at both ends, although at this time the leaking was less than it had been. The area of the spill was estimated by Kennedy to be approximately 20 ft in length by 12 ft in width with a depth of four inches. About half the liquid was in the stones underneath the vessel. Kennedy estimated there to be some 1,300 l of liquid on the ground. Peter Wilson rang the plant manager, Will Harrison to inform him of the GP922 leak. Harrison asked him to call Peter Coleman in Melbourne and to get Mike Shepard to investigate the cause of the leak. Wilson then rang Coleman. However, he was not available so Wilson left a message with Coleman's secretary asking for Coleman to call back.
- 3.45 At 11:35:05 Ward asked Rawson whether the bypass on the level control valve, LC9B, on Absorber B was open. Rawson said that he would have a look and asked whether Ward wanted it open or shut. Ward's reply was that Rawson should close it and then "we're back in control here". By this time, Hector was having trouble with the propane pressure in the GP1 refrigeration system. The pressure was low and for that reason Ward asked Brew at 11:36:51 to shut down about half a dozen fans in the KVR area. At 11:38:04 Ward informed Rawson that there was a low level shutdown on the Condensate De-ethaniser Reboiler, GP502A, so that it needed blocking in. Rawson replied that he was at Absorber B and that the LC9 valve was wide open and that he was blocking it in. Ward told Rawson to let the level controller do its job and that it should be right so long as the bypass was shut. Rawson said that he did not think that they had a level in there. Ward replied that they had previously had over 105%, but that now they were controlling it at 56%. Rawson said he would leave it.
- 3.46 At 11:40:24 Brew said that he had the propane fans "knocked off". At 11:49:06 there were falling temperatures in Absorber B and Ward asked Rawson whether the TRC3B bypass was open. Rawson replied that it was open a long way. Rawson then told Miller that he was going to get some lunch as everything had been shut down and was under control. At 11:50:44 Rawson was asked by Visser where he was and he replied that he was in the canteen.
- 3.47 The liquid which had leaked from GP922 was being collected in drip trays, but these had overflowed. Visser and Kennedy asked Lowery, the maintenance supervisor, to arrange for maintenance staff to retension the bolts on the leaking flanges of GP922 while operations

personnel pumped the spilled liquid into the open drain system which is a pipework system used for the safe disposal of liquids. Lowery arranged for Bruce Robinson, a mechanical technician, to investigate the spill. Subsequently, he arranged for Shane Vandersteen, a maintenance fitter from the CSP, and Andrew Knight, a fitter employed by an outside contractor, to attend to the retensioning of the bolts. The operations technicians who were pumping the liquid into the drain were Brew, Foster and Wheeler. They were part of the day crew.

3.48 When Vandersteen arrived at GP922 with Knight, he estimated the spill at a bit over 1,000 litres, although Wilson told him that he thought it was about 3,000 litres. Visser estimated the spill at 500 to 1,500 litres. Vandersteen and Knight checked the tensioning on both ends of GP922 and found that it was within specification. Lowery also asked Vandersteen to check the flange on one of the pipes on the top of GP922. It was not leaking at the time and was found to be tight. Vandersteen noticed that the east end of GP922 was completely frosted up, as were some of the connecting pipes. The frost was half an inch thick.

3.49 The production co-ordinator, Mike Shepard, arrived back at Longford, having been to Sale to see a chiropractor. Shepard said he went through the gate at around 11.45 am. Ward on the other hand, said that Shepard arrived at the control room about 11.30 am. Ward said that by that time Wilson, Kennedy, Visser and Peter Hiskins, the construction site superintendent, were also in the room and that there was a general conversation about what was happening. There was then no gas flow or lean oil circulation, the temperature in Absorber B was about -35°C, the Rich Oil Flash Tank had a low level (26% level on the LRC1 chart) and the ROF reboilers were shut down. The ROD and its reboiler would have been at about -48°C.

3.50 The actual time of Shepard's arrival was recorded by the gate pass time clock. The gate clock recorded Shepard arriving at 11.42 am. However, the clock was shown to be four minutes fast. Accordingly, the correct time of his arrival on-site was 11.38 am.

3.51 Upon arriving at the plant, Shepard went to his office and at the door met Peter Wilson who told him that there was a leak on the GP922 exchanger. Wilson wanted Shepard to accompany him to GP922 to assess the volume that had been spilled in order to determine whether there was a reportable incident. Regulations require that any hydrocarbon leak greater than 200 kg is to be reported to the Country Fire Authority (CFA). Shepard says that this was the only reason why he subsequently went to GP922.

- 3.52 Shepard then put on his safety gear and he and Wilson went separately to the GP1 control room. On his way to the GP1 control room, Shepard noticed that the feed line to the ROD was frozen. It was covered with white ice. The ice covered the whole length of the pipe which ran from the piperack at the top of the control room area to the tower. Shepard says that he arrived at the control room at about 11.55 am. Upon so doing, he learned that the ROF reboilers were off line and that an attempt was being made to establish lean oil circulation.
- 3.53 Shepard then went out to GP922. After a conversation there with Wilson and Lowery, Shepard decided that the GP922 leak was not significant at that time.
- 3.54 He observed Kennedy and Visser opening the LC10 block valve to allow rich oil to return to GP922 and then back to the ROF. Shepard returned to the control room where Ward pointed out that TRC3B recorded a temperature of -48°C and that the temperature was still dropping.
- 3.55 In the meantime, Rawson had taken his lunch back to the GP1 control room and was eating it when Visser came in and asked him to help Shepard, who was out in Rawson's area. Rawson agreed to do so. But he says that when he had finished his lunch, two electricians came in and asked him to go to the switchgear building to pull out the GP1202A breaker. Previously Visser had merely opened the breaker. Rawson's presence obviated the need for a permit. Rawson says that they went out, pulled out the breaker and attached the appropriate locks and tags. Rawson then sought out Shepard who was at GP922 with Lowery, Kennedy, Brew, Foster and Wheeler. He asked Shepard what was going on. He thought that, as he was the ROD/ROF area operator, he should have been made aware of what was happening in his area and this had not been done.
- 3.56 Brew says that he went with Kennedy to help start a GP1204 pump. At 12:04:22 he indicated to Ward by radio that he was going to start a GP1204 pump and Ward told him to go ahead. This was necessary because the GP1201 pumps would not run unless a GP1204 pump was running. Brew says that he and Kennedy checked the valves on the suction side of the GP1204 pumps to ensure that they were open and that he then started one of the pumps by depressing the start button. He says that, although the pressure rose as if the pump was pumping, there was no flow. Shepard was told by Kennedy that a GP1204 pump was running, but Shepard observed in the control room that there was no flow.
- 3.57 At 12:09:01 Shepard instructed Kennedy by radio from the control room to put the FRC11A and B flow control valves into bypass. That was the flow controller that regulated the flow

of lean oil through the ROF reboilers, GP501A and B. A flow was established through the reboilers and Shepard told Kennedy of this at 12:11:36. Starting at 12:12:55, there was a conversation between Kennedy and Shepard as to whether a second GP1204 pump should be started. Shepard says that he wanted a flow in both the ROF reboilers, which had not been re-lit, because they had a large radiant area in them which would drop the temperature of the circulating lean oil. Putting a flow through both heaters would not have changed the GP1204 discharge. At 12:13:16 Ward told Kennedy that there was a flow in both heaters and that was the way they wanted it. The control room charts show that flow restarted at 12.11 pm.

3.58 Vandersteen and Knight, who had been retensioning the bolts on the GP922 flanges, finished their work at about 12.15 pm without making any significant changes to the bolt tensions or the rate of leakage. There appears to have been some difference of opinion as to whether the leaks could have been stopped without replacing the flange gaskets and whether GP922 should have been isolated and depressurised to allow this to proceed. In the end it was apparently decided that the best method of stopping the leakage was to warm the vessel slowly by restarting the flow of warm lean oil. The plan that evolved was to bring the lean oil back into circulation, but to leave the GP501 heaters off so that the oil would be relatively cool. The GP501 heaters had been off for an hour by then and were not re-lit. The intention was to circulate lean oil through them in the hope that their large surface area would provide cooling for the lean oil and thereby reduce any thermal shock.

3.59 After Vandersteen and Knight had finished their work, Vandersteen saw Kennedy and Brew walk away to the south. He then heard a pump start up after which Kennedy and Brew returned. Vandersteen assumes that it was a GP1204 pump which was started. Vandersteen said that GP1201C was then started up. Knight said that Visser and Brew were stopping and starting the GP1201 pumps. Kennedy said that at that stage both the GP1204 and GP1201 pumps were started, but that, as there were a number of operators, he did not know who started which pump. Vandersteen and Knight then observed Kennedy opening the LC10 block valve allowing flow to GP922. This immediately caused the vessel to start leaking again. Knight says that there was leakage at both ends of GP922 and that liquid was fanning out four feet in a semi-circle from the bottom half of the heat exchanger head. Kennedy agreed that a leak occurred when a small ROD bottoms flow was established and that this was then shut off. At this stage Vandersteen and Knight felt the situation was dangerous and they left the area.

3.60 Brew says that, after starting the GP1204 pump, he went with Kennedy to start a GP1201 pump and that, in the presence of Kennedy, he started one by depressing the start button.

Kennedy then left the area of the pumps but Brew remained in the vicinity. At 12:14:26 Ward and Shepard looked at the charts in the control room and established that there was no change in the level in the Oil Saturator Tank. Brew says that shortly thereafter they were made aware by the control room that there was no flow through the GP1201 pump that had been started. This appears to be a reference to a conversation recorded as being between Brew and Ward, but which Brew believes was between Kennedy and Ward. During that conversation Ward instructed either Brew or Kennedy at 12:14:41 to “just swap the booster pumps over for us”. Kennedy returned to the area and Brew says that he and Kennedy observed that the pump which Brew had started had now stopped. Brew says that he attempted to start another pump by depressing the start button, but there appeared to be no flow. However, the pump continued to run and, although Brew has no recollection of it, the radio transcript records someone saying to the control room at 12:17:23 that there was a flow “and it’s the flow through the level controller”. It may have been Kennedy who said this.

3.61 At about 12.10 pm, Visser left GP1 and says that he went to the Administration Building to see Peter Wilson. He says that he thought that Wilson had returned to his office and that he wanted to see him about the gaskets on GP922. When Visser arrived at Wilson’s office there was no one there. Visser says that he headed back to GP1 and on the way stopped to have a smoke at the smoko shed. He says that he walked to Wilson’s office without ringing him first, because he wanted time to reflect. He was in the smoko shed when the explosion occurred.

3.62 As mentioned earlier, before 12 noon Wilson had rung Peter Coleman, the operations manager in Melbourne. He was not available and Wilson had left a message for him to call back. Coleman says that his secretary informed him that Wilson had said something to the effect that there was no problem, only a small spill, and that he was calling because they were told Coleman needed to know. Coleman returned Wilson’s call but Hiskins answered the telephone. He said that Wilson was down at the plant. He told Coleman that the spill was larger than had been relayed to him and that they were cleaning it up. Coleman told Hiskins not to call Wilson out of the plant if he was working on the problem but to get him to ring back when he was ready. At 12:08:52 Hiskins contacted Peter Wilson and told him that Peter Coleman wanted to speak to him.

3.63 Subsequently, Wilson came into the control room and rang Coleman. The telephone records show that this conversation took place at 12:20 pm and lasted about four minutes.

- 3.64 Coleman says that Wilson explained that Harrison, the plant manager, had asked him to notify Coleman that they had a lean oil leak on to the stones from the head of the GP922 heat exchanger, that they were tightening the head and that they were in the process of cleaning the spill with pumps and absorbent materials. Wilson said that the situation was under control and posed no danger at the time. Coleman says that he asked Wilson what had caused the leak and that Wilson explained that the shift felt that there was a problem in the absorbers, a potential block, possibly a hydrate, causing a loss of flow of rich oil in the system. Wilson said that they were trying to find out more. He said that he had also called to notify him that GP1 had been shut in and all the vapours had been redirected to GP2. He added that gas sales would not be affected because the order was only 15 Mm<sup>3</sup>/d, and could be met by GP2 and GP3. Coleman says that Wilson's voice showed that he was in a hurry and that he did not detain him.
- 3.65 At some time after 12:16:56 Shepard left the control room and went back to GP905. He looked at GP905 and saw ice on the areas where there was no insulation. He said he realised that if the temperature got too low there was a danger that an impact could cause a brittle fracture. By this time lean oil flow had, in all likelihood, been established.
- 3.66 Accordingly, Shepard sought to minimise the flow of lean oil through GP905. He looked at the TRC4 Valve 1 and observed that it was closed. To obtain minimum lean oil flow through the GP905, this valve had to be fully open. To achieve this, he asked Ward to close TRC4 so as to open Valve 1. This instruction was given at 12:20:52. However, Ward misheard the instruction. He thought Shepard said PRC4 not TRC4. PRC4 was the pressure controller for the Rich Oil Flash Tank. As a consequence of this misunderstanding, Ward made no adjustment to the TRC4 controller position and the controller output remained fully open.
- 3.67 Shepard remained at TRC4 waiting to see TRC4 Valve 1 open, which he knew it should do when Ward carried out his instruction. In fact nothing happened. The valve did not move. Shepard was confused by the lack of response. His confusion was compounded, when, over the radio, he heard Ward confirm that TRC4 was closed. In fact, in this radio exchange, Ward had referred to PRC4 rather than TRC4, but Shepard did not pick this up.
- 3.68 In his evidence Shepard said that at some point he switched the mode of operation of TRC4 from demethanising to de-ethanising mode, using the HS4 switch. Although he felt that he had made this change before his initial instruction to Ward to close TRC4 at 12:20:52, this does not accord with the radio evidence and his stated objective.

- 3.69 At 12:25:31, he instructed Ward to “go for maximum output” on TRC4. It is likely that it was at or around this time that Shepard operated the HS4 switch. His motivation in doing so, was to try and get the TRC4 Valve 1 to open to minimise lean oil circulation through GP905. It would appear, however, that he was not sure what the outcome of operating of the switch would be. In all probability, it was only a moment or two after operating the HS4 switch that Shepard looked at TRC4 Valve 1 and observed the stem rising as the valve began to open.
- 3.70 At around this time, Brew had decided to go to lunch. He was commencing to ride his bicycle along the path at Kings Cross, when the GP905 ruptured.

# Chapter 4

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## THE EFFECT OF THE EXPLOSION

### *KENNEDY'S ACCOUNT*

- 4.1 For five minutes before the initial explosion, Kennedy was examining GP905 to see why there was no flow. He was at TRC4 when the explosion occurred. He was blasted into the air, struck a solid object with his head and hit the ground with liquid, dirt and stones pelting him at a high velocity. He felt as if he were being shot at by a machine gun. Wherever he crawled he continued to be pelted. He smelt nothing because he held his breath. Eventually he saw a glimmer of light and crawled in that direction. He must have come out from behind something that was sheltering him, because he was rolled over and again exposed to the blast. He had his eyes closed. He crawled into the clear and noticed two other blackened persons crawling towards the control room. He now believes them to have been Shepard and Foster. Kennedy then stood up but fell over. Blood was flowing from an injured eye. Miller assisted him towards the control room. He glanced over his shoulder and saw white vapour everywhere. GP905 had been skewed at an angle and there was still a loud roar of vapour and liquid.
- 4.2 Kennedy was taken to the lunch room and then into the control room. He says that alarms were going off everywhere and someone was trying to contact an ambulance. He could still hear the roar of escaping gas and liquid. Then he heard a loud whooshing sound of gas igniting, followed by two enormous bangs that shook the building on its foundations. The control room lost all communications and the air conditioners shut down. Other injured personnel were brought into the control room. Andy Noble escorted Kennedy to the first aid room and on the way he heard another loud bang. Because the first aid room was crowded, Kennedy suggested that he be taken to the canteen. He was continually passing out. Kennedy heard another five or six explosions. He was taken to the Sale hospital by ambulance, where he received stitches in his forehead. Later he was taken by ambulance to the Melbourne Eye and Ear Hospital. Kennedy suffered a number of injuries, including bruising to his head, damage to his right eye, chemical and cold burns and general bruising. He recalls seeing Lowery and Peter Wilson about five minutes before the initial explosion. He estimates that they were about five metres from where he was.



### ***SHEPARD'S ACCOUNT***

- 4.3 Immediately before the explosion, Shepard looked at GP905 and saw that there was no change in the level of icing. He looked around and observed the TRC4 valve opening as the stem rose. There was no warning of the explosion. Shepard heard a boom and there was a violent release of white vapour. The next thing that Shepard remembers is that he was on his hands and knees totally surrounded by vapour. He could see the contents of GP905 roaring out. He crawled away from the noise towards the Emergency Shut Down box. On the way, he bumped into either Foster or Kennedy and was grabbed by Steve Young, who dragged him into the GP1 control room.
- 4.4 Shepard then saw fire coming from a southerly direction. There had been no fire before that. The fire enveloped the whole area around GP905 and GP922. Shepard was disoriented. Young apparently walked him to the first aid room, but he has no recollection of that. He only remembers sitting up in the first aid room. He was placed in an ambulance and at this stage heard another large explosion. Shepard was taken to the Sale hospital, but was not seriously injured.

### ***FOSTER'S ACCOUNT***

- 4.5 After assisting Miller to transfer the KVR gas to GP2 and to restore the electrical tie between GP1 and GP2, Foster had gone to GP922 and had helped John Wheeler to dig trenches to drain away the spillage. After lunch, Foster had returned to GP922 to dig some more trenches. He was about to start when he heard a loud thundering noise. He was struck by sand and gravel and found himself on his side, his vision obscured by a white vapour cloud. Holding his breath he crawled between GP922 and GP905 and met Shepard who was near the footpath. Foster had been able to stand up at that point and continue with Shepard to the control room where he was helped in the west door by Bennett.

### ***CUMMING'S ACCOUNT***

- 4.6 Cumming, an operations technician in the CSP, had been having lunch in the lunch room of the GP1 control room with Rawson. After Rawson left to attend to the breaker for the GP1202 pump, he heard a long rumbling sound like a thunderstorm in the distance. He got up to leave when he heard another louder rumbling sound. Aware that there was a fixed fire monitor north-east of the control room, he made his way to it. Outside there was a vapour cloud surrounding the ROD/ROF area. Cumming says that it was high and wide like a thick fog cloud rolling out. It was half the height of the ROD tower. There were no flames at that stage. Cumming decided to attempt to disperse the cloud with the monitor.

- 4.7 Shortly before this, trainee operators Marty Jackson and Jason Watson had arrived in the control room area. They had been having lunch in the canteen with their training supervisor, Andy Noble. They had heard two explosions, the second being louder. Noble told them to report to the control room and they made their way there. Cumming told them to get ground monitors. He proceeded to hose down the vapour cloud in an arc with the monitor which he was manning. The cloud moved slowly away from him, more because of a breeze than the water. Cumming then moved to another fixed monitor and turned it on. By this time he could see that the source of the vapour was near the ROD tower and that was where the sound of a pressure release was coming from. He directed water towards the east end of GP905. After adjusting the direction of the water stream several times, he heard a whoof and saw orange flames in the location of the eastern end of GP905 and GP922. They reached up into the overhead piperack. Cumming went and got a chemical fire extinguisher which was on wheels and wheeled it near to the eastern end of GP922. There he unwound the hose and activated the equipment, which sprayed out a large cloud of white powder. It succeeded in putting out pools of fire on the ground, but as soon as it was directed to another place, those pools would re-ignite. There was a large orange flame coming from the east end of GP905 and extending up into the east/west piperack. Cumming observed that there was a lot of damage to GP905. It was up in the air at the east end about three feet higher than normal. The chemical fire extinguisher lasted about twenty seconds and Cumming found himself in front of the fire in only his work overalls. His safety hat had fallen off when he was running between monitors. He decided to get some firefighting gear from the control room and made his way to the west door.
- 4.8 On the way out of the north door of the control room, Cumming passed Kennedy who was being led to the control room and looked to be painted black. He was walking but staggering. Outside the control room, Cumming met Rawson whom he advised to get firefighting gear. Rawson went inside the control room to get the gear, but came out saying that he could not breathe in there. Cumming went into the control room and smelt acrid fumes which stung his throat. He grabbed a breathing apparatus which was one of three sets in the control room and went outside to put it on. He re-entered the control room. He saw Greg Foster on the floor. He was completely covered in a black paint-like substance and had an oxygen mask over his nose and mouth.
- 4.9 Cumming decided that the oxygen mask which Foster was wearing was admitting some of the fumes in the control room and that he should move out. He helped him to do so. Others took Foster to the canteen and he was eventually conveyed by ambulance to the Gippsland Base Hospital where he was treated for chemical burns, abrasions and broken ribs.

- 4.10 Cumming left the control room and went back to GP905 to assess the fire. Numbers four and five monitors were not reaching the piperack upon which the fire from GP905 was impinging. Cumming thought that some ground monitors closer to the fire were needed. He managed to cart a ground monitor to the eastern end of GP922 and to direct water on to the piperack. While he was positioning the monitor, some of the smaller pipes in the rack ruptured and added to the fire. After adjusting the monitor, Cumming returned to the west side of the control room and obtained another monitor in a wheel barrow to place beside monitor ten. He placed it on the ground where it disappeared in a foot of foam. The Esso fire truck had been set up and was spraying firefighting foam over the area covering everything, including Cumming. He decided that it was too dangerous to be so close to the fire and that he should attempt to isolate the fuel to the fire.
- 4.11 He then checked the Emergency Shut Down (ESD) box to make sure that it had been activated for GP1. It had. ESD is an automated system for shutting off the main flows of all gasses and liquids in and out of the plant. Cumming swung all the other handles with the exception of those for the generators. He then proceeded towards the GP1 molecular sieves to check that the inlet gas was shut in, but the pressure on his breathing apparatus gave out. He obtained another breathing apparatus at the southern end of the Amine Switch Gear Building and made his way to the GP1 inlet station where he found that the inlet valves had been shut in. He also found that the GP2 stripper overheads ESD valve to GP1 had been shut in, as had the GP2 debutaniser bottoms ESD valve. Cumming then thought that the slugcatcher condensate might be feeding the fire, so he checked the hydrocyclones. The control valves had shut, but to make sure, he attempted to close a block valve by hand. It was too tight for him to do so without a valve key. At this time, Visser was calling for additional operators to come to the fire shed. Before returning there, Cumming checked one other possible source of fuel to the fire: the ROF lean oil make up. He found that it was off.
- 4.12 After returning to the fire shed, Cumming went to the CSP intending to shut in the CSP vapours to GP1. He found a valve key and started to lever the valve shut. The fire was getting worse. He managed to get the valve within two inches of being closed when the hand wheel fell off making the valve inoperative. At that time the last explosion occurred. Cumming made for the main gate, meeting with others going in the same direction at the canteen.

### ***VISSER'S ACCOUNT***

- 4.13 Upon hearing the first explosion, Visser ran towards the control room. While he was running he saw a ball of flame coming from the area of GP922. He says that he went into

the control room and yelled out to shut down GP1. Ward said that he had done this. Visser instructed Ward to start the emergency response of phoning out all lists. He also instructed Ward to hit ESD1 and activate the emergency alarm. Visser went outside and saw a ball of flame around the exchangers GP922 and GP905. Visser said he saw Cumming at the ESD box activating the Emergency Shut Down system. The emergency alarm was activated simultaneously. Whilst outside, Visser put a monitor over the area of the fire in an attempt to keep it cool. Other people activated other monitors. Visser went back towards the ESD panel taking someone to the control room away from the flames on the way. He then attended to the establishment of additional monitors and fire hoses. Cumming and Bennett were in the vicinity. Visser was untangling some hoses when he came across Shepard and Wheeler who had been injured. Visser also encountered Foster and gave instructions that he be taken to safety under cover.

4.14 Visser went back to the monitor near the control room and redirected the monitor on to the fire. As he was about to leave, he saw movement by the base of the fire. He dragged the person by the collar away from the flames. It later turned out to be Heath Brew. Visser then went and asked Jackson to help him with Brew, which Jackson did. They dragged him alongside the switchgear building away from the heat. They then put him on a stretcher and took him behind the control room. Jackson says that he could not recognise Brew at the time. He was black, burnt and appeared to have no teeth because they were coated in carbon. His overalls were off one leg, which appeared to have been cauterised.

4.15 Soon after this, the fire truck came and directed foam on to the fire. Visser had been trying unsuccessfully to radio for first aid so he ran up the road to the old guard house where he spoke to Delahunty, an operator from the offshore control room in GP3, and asked for a head count. He was told that one had not been completed. The control room operators informed Visser that they had been evacuated. Visser says that he went back into GP1 and there was a second and large explosion. He moved back to the road near the fire shed and attempted to organise matters on the radio. Visser remembers calling for Peter Wilson whom he was unable to reach. There was a third explosion and Hiskins conveyed by radio his decision to evacuate the plant. Visser then moved outside the gate. He was still asking for a head count to be done. This involved persons pressing the emergency button on their radios. Each radio was issued by number to a person and there was a monitor which indicated when its emergency button had been activated. Visser never obtained a completed head count, but when he became aware that not everyone had been evacuated, he spoke with Hiskins about it. It was apparent that at least two persons were still in the plant but it was too dangerous in Visser's view for anyone to go in. Visser went to the heliport, to which

people had been evacuated from the administration section, and was told that he was to go to hospital for the treatment of some minor burns.

### ***RAWSON'S ACCOUNT***

4.16 Rawson was at the ROF reboilers at the time of the explosion. He heard a huge thump, looked towards GP922 and saw a whitish cloud of vapour as high as the piperacks moving in a south, south-east direction. Rawson told Ward by radio to shut down all heaters lest they provide a source of ignition. This was recorded at 12:26:01. As the cloud of vapour was moving towards Rawson, he got on his bike and rode towards the LLR plant. He turned west on South Road and at the intersection of that road and the Control Room Road looked towards the heater area. There was a clear flame as high as the piperack in a ball-like configuration moving back to GP905. Rawson rode west another 10 to 15 feet, looked back and saw and heard a loud explosion. It was an angry red and black colour and was half as high as the ROD tower. Rawson continued north on the Crude Centre Road, being prevented from proceeding along the Control Room Road by the intensity of the blast in the area of the GP1 control room.

4.17 On arriving at GP1, Rawson entered the control room by the north door. There he met Grant Cumming. Cumming was putting on a set of breathing apparatus and told Rawson to grab a set and come with him into the GP1 control room. On opening the door to the control room, Rawson was struck with an acrid smell which prevented him from breathing. He located a portable fire monitor outside and directed water towards the GP905 area. There was another explosion as he did this. Rawson then went to the first aid room where he saw Kennedy and Fahy, an operator from GP2. The latter was in a state of shock and was not breathing properly. There was another explosion and someone asked Rawson to take Fahy to the canteen, which he did. There was a further explosion and a call to evacuate the canteen. Rawson and four others carried Fahy up to the main gate in a chair. He was placed in an ambulance. Rawson then heard Visser on the radio calling for persons to come down and help fight the fire, so he made his way back towards the canteen. He was nearly there when there was another explosion and he felt it necessary for his own safety to return to the main gate.

### ***MILLER'S ACCOUNT***

4.18 After finishing lunch, Miller left the GP1 control room to look at the compressor, GP308. He was about 30 metres from the north door of the control room when there was a roar. He turned around and saw a huge, swirling cloud of stones, dirt and gas coming from the vicinity of GP922. He could see the edge of the vapour cloud but could not see through it.

It was spreading away from him towards the south. He saw Cumming run out of the north door of the control room towards a monitor north of the Oil Saturator Tank. Miller turned the water on and Cumming aimed it over the area of the gas release.

4.19 Miller saw a person who was black from head to toe standing at the western end of the GP922 area. He ran down the eastern side of the control room to him. It was John Wheeler. Miller grabbed him and told him to get out of the area. Miller looked around and saw another person who was also black. It was Ian Kennedy. Miller grabbed him and took him inside the control room by the north door. He asked Hector to keep an eye on Kennedy.

4.20 As he was about to leave the control room, Miller heard a very loud explosion. He went to the north area and saw a huge fireball in the area of the GP905 and GP922 heat exchangers. He realised that he had firefighting duties to perform when the fire horn sounded. He went to the Utility Building 204 and started the diesel fire pump, putting the electric pump to standby. He then went to a monitor on the east side of the fire, turned it on and directed it at the flames. He believes that there may have been another explosion then and he left, walking past the dehydrators where there were small spot fires.

4.21 Miller there met Gallagher, who helped him to put out the fires near the dehydrators. Miller then made his way to the first aid room which was being evacuated. He gave assistance, but heard Visser calling for any spare operators to go to the fire shed. Miller made his way there and advised against turning on another ground monitor because it would only reduce pressure to those already being used. As he started to move back up the road there was another large explosion. He then went with McMahon to check on the pump on the south pond and, having done that, made his way via the GP2 control room to join other maintenance people at the turnstile. Subsequently, Miller checked the level in the GP3 water storage tank and the aeration bypass. When the decision was made to evacuate the plant he left via the turnstile and ended up at the intersection of Garretts Road and Seaspray Road.

### ***COLEMAN'S ACCOUNT***

4.22 Steve Elston, a vessels inspector at the Longford plant rang Coleman from the Longford Emergency Response Procedure room (ERP) and told him of the explosion. He said that he thought the explosion had been in the KVR building. He said that he, Angela Jones and Mike Marshall were manning the ERP room. Coleman instructed Elston to remain there until he was relieved. Coleman immediately initiated the call out of the Crisis Management Team. This required the team to assemble in the conference room on the 10th floor of the Melbourne building. There Coleman received another call telling him that there had been

further explosions. Coleman spoke to Elston again and instructed him to evacuate the ERP room to the heliport and establish an ERP room there. He inquired about the whereabouts of Wilson and Hiskins. Elston said that he did not know where they were but that they were currently conducting a head count on-site. Coleman subsequently received a call from Hiskins asking why the ERP room should be evacuated. Coleman replied that he was concerned about the potential for escalation and instructed him to complete the evacuation to the heliport. He again asked about Wilson and was told that there were a number of people unaccounted for and Wilson was one of them.

- 4.23 Shortly after forming the Crisis Management Team, Coleman discussed the crisis with the directors of Esso and was requested to form a small response team to travel immediately to Longford. He did so and they left the Melbourne office within thirty minutes. They flew in the Esso plane to Sale and from there by helicopter to Longford.

### ***WARD'S ACCOUNT***

- 4.24 Upon hearing the first explosion, Ward shut in PRC4. Through the glass of the southern control room door he could see a cloud of vapour travelling from east to west. Once the cloud had gone, he saw Shepard and Foster travelling west on the footpath. They were both burnt. Ward activated the fire alarm. From the door he saw flames impinging on the pipework. He then went outside and activated ESD1 on a panel adjacent to the control room. He returned to the control room and advised the guard house that there had been an explosion and fire. He asked for ambulances, fire trucks and a rescue vehicle at the control room as soon as possible. He then initiated the emergency response on the telephone by requesting a list one call out.
- 4.25 Someone had propped open the control room door with a fire extinguisher. Through the doorway Ward could see what looked like GP922 well alight. There were explosions across the walkway. Insulation was falling out of the piperack. Ward started to inhale acrid fumes, which were invisible. They hurt his throat and lungs and made it difficult to breathe. He took the fire extinguisher away and closed the southern control room door. He went to the west control room door to get a breathing apparatus and was intercepted by Jackson screaming for a stretcher. They obtained one from the storeroom and Ward helped Jackson load Brew on to the stretcher under the direction of Visser.
- 4.26 Ward was having difficulty breathing despite having by then obtained a breathing apparatus. There appeared to be no pressurisation in the control room and an electrician was called. Pressurisation was restored. Through the southern door Ward could see that the fire had escalated. He thought that he was in danger if he remained in the control room. The

telephones and radio were dead. He checked the control room building to see if anyone remained there and left through the north door.

4.27 There was then another explosion and Ward saw the fire crew withdrawing from the fire truck which was parked at the north end of the control room. He went with Hector to the ERP room to see if he could lend assistance. There Hiskins told him that everyone had been instructed to evacuate to the heliport. Hiskins asked Ward to go to the canteen where the injured were and tell them to evacuate. By the time Ward got to the canteen most of the people there had gone. He went back to the ERP room, which was then empty. He met Hiskins on the footpath and they joined the rest of the shift who were at the car park adjacent to the canteen. From there they observed the fire escalate. The cladding on the absorbers was on fire and the ROD tower was engulfed in flames and smoke. Visser was at the fire shed and made a request over the radio for operators to go in and set up ground monitors. A couple of operators told him that, as a crew, they were not prepared to do it. Visser said that he could not force them to do anything. The biggest explosion to that time then occurred. Ward had been coughing and wheezing for some time and began to feel faint. He left the car park and obtained treatment with oxygen from an ambulance officer. At 1.10 pm he was taken to the Sale Hospital where he was treated and discharged that afternoon.





# Chapter 5

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## TECHNICAL ANALYSIS

- 5.1 From those records that are available, it has been possible to calculate process conditions not directly observable. This has enabled conclusions to be reached about the operation of GP1 in the hours leading up to the accident, otherwise than by reference to the direct evidence of those working on the plant at the time. This process was crucial to determining the immediate causes of the accident. It allowed missing data to be reconstructed and the systematic and scientific assessment of numerous hypotheses. These were rigorously challenged, and most were rejected as implausible technically or because they were inconsistent with the factual evidence. Only those that passed this scrutiny were retained. This chapter presents the technical basis for the sequence of events that is considered, on the balance of probabilities, to have caused the catastrophic failure of GP905. The analysis follows the general course of events on the morning of 25 September.

### ***HIGH CONDENSATE FLOWS***

- 5.2 The two absorbers were designed to remove condensate from the incoming gas. It is convenient to use Absorber B as an example in the following description. Absorber A was identical to Absorber B, except for the equipment numbering. The bottom section of the absorber was designed to remove the liquid condensate contained in the chilled feed gas to the absorber. However, not all condensate that entered with the feed gas was removed in the bottom of the absorber. Calculations have shown that even under normal conditions, between 10% and 15% of the incoming condensate was entrained in the gas travelling up to the absorption section where it combined with the rich oil stream. Additionally, a portion of the condensate that passed to the bottom of the absorber was revaporised through the action of GP903B and TRC3B.
- 5.3 On the morning of the accident, the primary route for the removed condensate was via exchanger GP919 to the Condensate De-ethaniser, GP1106A. When the condensate temperature in the bottom of Absorber B was too low, more condensate was produced than GP919 was capable of effectively heating. Upon this happening, controller TC9B restricted the flow of condensate to GP919 and the level in the bottom of the absorber increased. Eventually, this level increased to the point where excess condensate overflowed into the rich oil stream. This overflow of condensate was not directly measurable or observable, but

can be calculated based on knowledge of the physical processes occurring. A computer simulation was therefore used to calculate the flowrate of condensate into the rich oil at different times on the morning of 25 September 1998.

- 5.4 During the night shift which commenced at 7.00 pm on 24 September, difficulty was experienced in dealing with the volume of condensate arriving at the slugcatchers. The slugcatcher known as the Barracouta Slugcatcher had been off line since 20 September, but was brought back into service at 3.00 pm during the preceding day shift. This resulted in a large slug of accumulated liquids, which peaked at about 11,500 kl/d and persisted until shortly before the end of the night shift. The records do not reveal why the Barracouta Slugcatcher had been out of service, but it was brought back into use because of a spell of cold weather which gave rise to an increased demand for gas. By 6.00 am on 25 September the ambient temperature at Longford had fallen to less than 1°C. At the shift handover at 7.00 am the rate of condensate flow from the Barracouta Slugcatcher had been reduced to a moderate level, and the handling of condensate was thought to be under control.
- 5.5 The levels of condensate in the bottom of both absorbers in the week preceding 25 September are shown in Figure 5.1. For half the night shift commencing on 24 September, condensate levels in Absorber B were above the 100% level and were at that level from 5.51 am until the end of the shift. After the shift change, the levels in Absorber B stayed above 100% until 11.26 am by which time there had been no inlet gas feed to GP1 for about 15 minutes.
- 5.6 The condensate temperatures at the base of the absorbers are illustrated in Figure 5.2. Condensate temperatures in Absorber A were automatically controlled close to -10°C during the night shift. However, the temperature of the condensate in Absorber B at shift change was about -18.5°C, having recovered from -20°C at about 5.30 am. It was the practice to set the temperature in an absorber to -20°C when it was delivering condensate to GP2, but this was not the case on 25 September. The appropriate setpoint was -10°C for both absorbers.
- 5.7 The constraint on the flow of condensate from the absorbers to the Condensate De-ethaniser was the heating capacity of heat exchanger GP919. The temperature of condensate leaving GP919 was controlled to 1°C in order to protect the Condensate Flash Tank, GP1105A, which, according to the (P&IDs) had a low operating temperature limit of -1°C. However, the TC9B override limit was set at -2°C and the alarm was set at -3°C on 25 September. When GP1 was originally designed, normal carbon steel was considered by the design standards of the day to be suitable for temperatures down to -27°C. Current design standards vary the allowable temperature depending on the likely stress levels in the vessel.

It appears that this  $-1^{\circ}\text{C}$  limit reflected these later standards. PIDAS data shows that at 7.00 am the temperature of the condensate leaving GP919 was  $-2.2^{\circ}\text{C}$  and that it remained below  $-2^{\circ}\text{C}$ , reaching at one point  $-4.2^{\circ}\text{C}$ , until 11.00 am, when incoming gas was isolated from the absorbers.

- 5.8 Figure 5.3 shows that TC9B was overriding LC9B continuously for the first five and a half hours of the night shift. The override then became intermittent. From 6.00 am onwards it was continuous. In this situation, the level of condensate was not controlled and would have varied depending on the balance between incoming and outgoing condensate. At certain times during the night shift starting on 24 September, the flow of incoming condensate exceeded the flow leaving, resulting in the condensate level rising rapidly until it was above the level that could be measured. It was then impossible for the operator to observe the actual level of condensate or any flow of condensate into the rich oil system.
- 5.9 As shown in Figure 5.1, at the shift change on 25 September, condensate levels in Absorber B had been over 100%, the highest recordable level, for 33 of the preceding 38 hours. This provided ample opportunity for condensate to carry up into the rich oil tray in Absorber B and to dilute the rich oil progressively. As discussed in paragraph 5.2, the gas entry in the bottom of the absorbers was conducive to such a carryover even when condensate levels were significantly below the rich oil tray. This tendency must necessarily have increased with high levels of condensate.

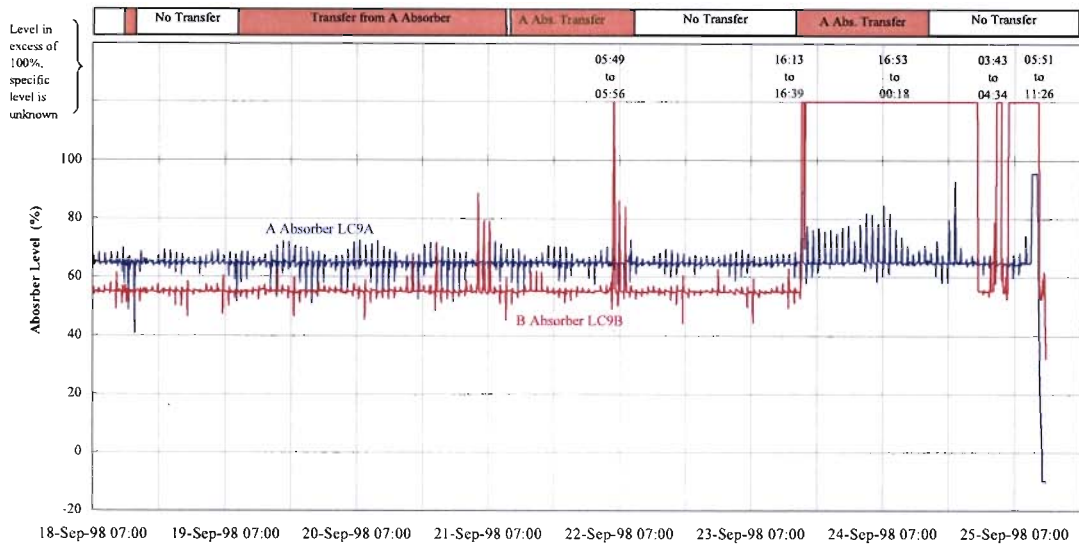


Figure 5.1 Absorber condensate levels 18 to 25 September 1998

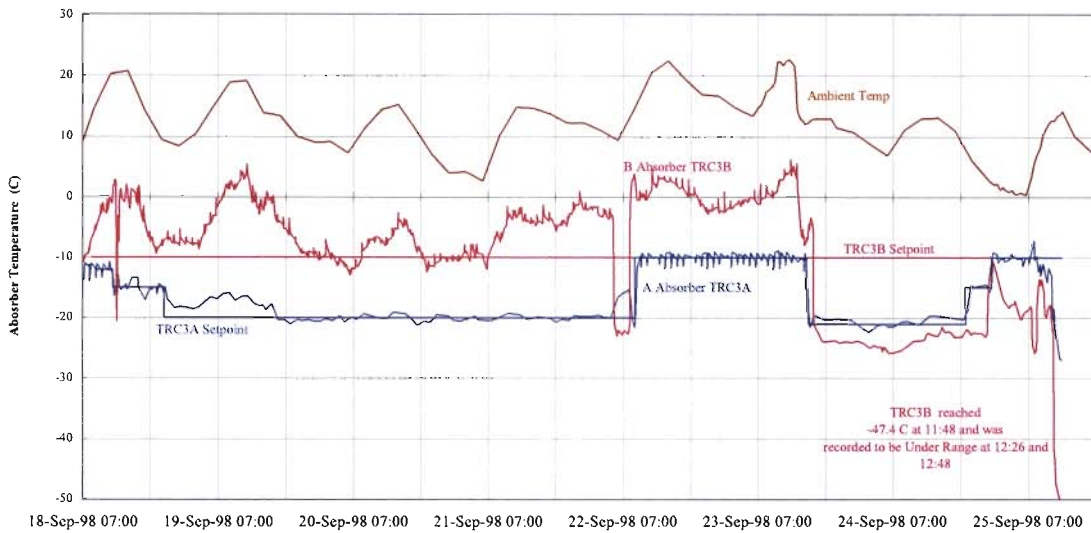


Figure 5.2 Absorber condensate temperatures 18 to 25 September 1998

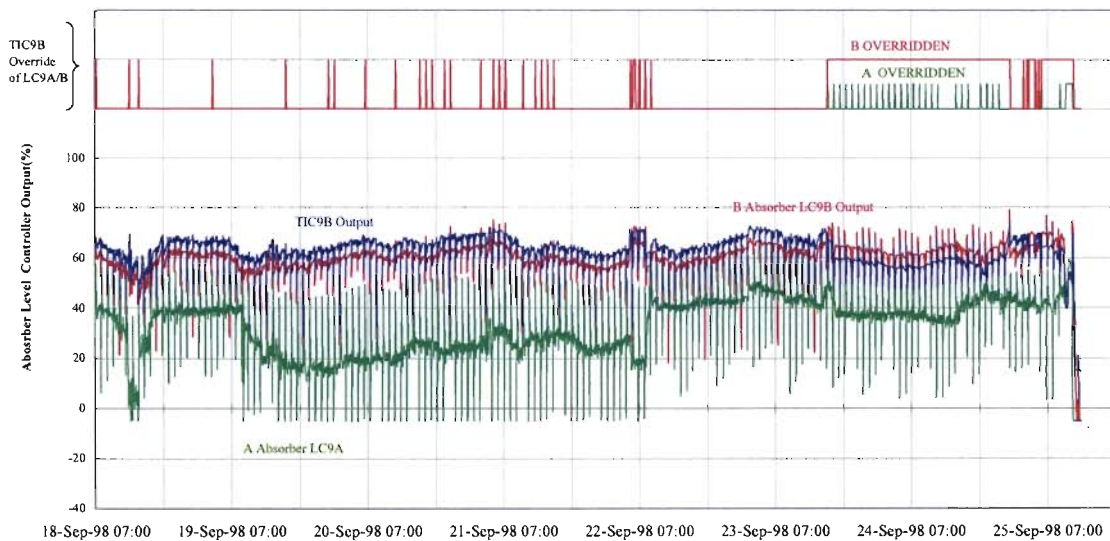


Figure 5.3 Absorber level overrides 18 to 25 September 1998

5.10 The flowrates of condensate entering the rich oil stream at different times between 11.00 pm on 24 September and 8.00 am on 25 September were estimated using the computer simulation (Figure 5.4). The bars in the figure show the flowrate of condensate leaving each absorber via GP919 and the rich oil stream. The line graphs show the corresponding absorber temperatures. It should be noted that these calculations show these conditions assuming that stable operation was achieved at the input conditions prevailing at that time. Time delays in the gas and liquid streams, and the complex dynamics of the various recycle loops feeding the absorbers, have not been quantified. This simplified analysis indicates that the flow of condensate into the rich oil stream peaked at 11.00 pm on 24 September and again at about 8.00 am on 25 September. Although at 6.00 am the inlet gas flow was higher, and the ambient temperature lower, the incoming condensate flow was also lower and it does not appear that the conditions at that time were more severe than at 11.00 pm on 24 September.

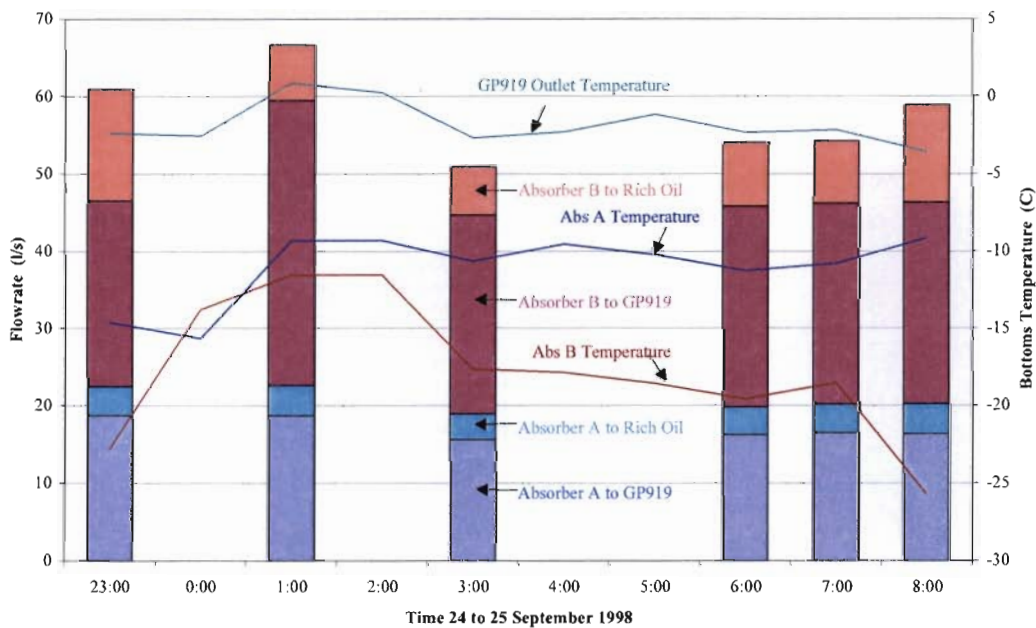


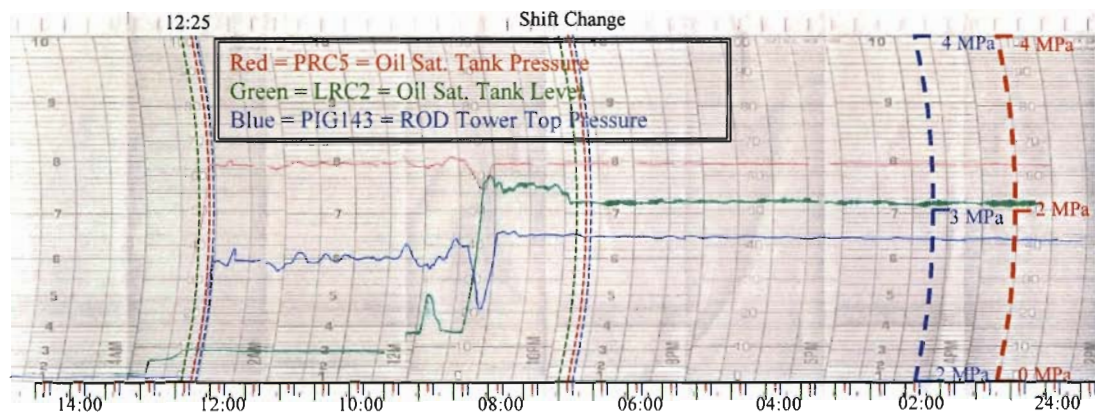
Figure 5.4 Estimated condensate flows 24 to 25 September 1998

5.11 As temperatures in the bottom of the absorbers were below  $-10^{\circ}\text{C}$  for a continuous period of 38 hours, and below  $-20^{\circ}\text{C}$  for much of it, the condensate produced during that period would have been highly volatile, containing larger proportions of methane and ethane than condensate formed at higher temperatures. As a consequence, a mixture of rich oil and this volatile condensate would have produced a larger volume of vapour as it expanded through the level control valve, LC8B, from 6,900 kPa to 4,500 kPa, the pressure in the Rich Oil Flash Tank. The simulation shows that as this material flashed, its temperature would have

dropped from  $-23^{\circ}\text{C}$  in the absorbers to  $-33^{\circ}\text{C}$  in the Rich Oil Flash Tank. These temperatures were approximately  $10^{\circ}\text{C}$  warmer than the minimum design temperature for the Rich Oil Flash Tank in the original Hudson design. However, they were not cold enough to activate the low temperature alarm LTA2 on the rich oil line from Absorber B. Nevertheless, these temperatures were colder than those during normal operation in which condensate did not overflow.

### ***CARRYOVER FROM THE ROD***

5.12 At the time of the shift change, the first visible signs of a process upset in the ROD/ROF area started to appear on those chart recorders that were operational. Earlier indications may have been visible to the operators. At 7.03 am the level started to rise on the Oil Saturator Tank as shown by level recorder, LRC2, and by 7.30 am it was significantly above its setpoint (Figure 5.5). Had all the installed chart recorders been operational, diagnosing the cause of this rise would have been straightforward. Unfortunately, the chart recorders measuring two of the important flows were not working. The cause of the level increase would therefore not have been readily apparent to the operators on the day. It has been necessary to deduce the cause of this rise in level from calculations based on those charts that were available, and knowledge of the physical behaviour of the system.



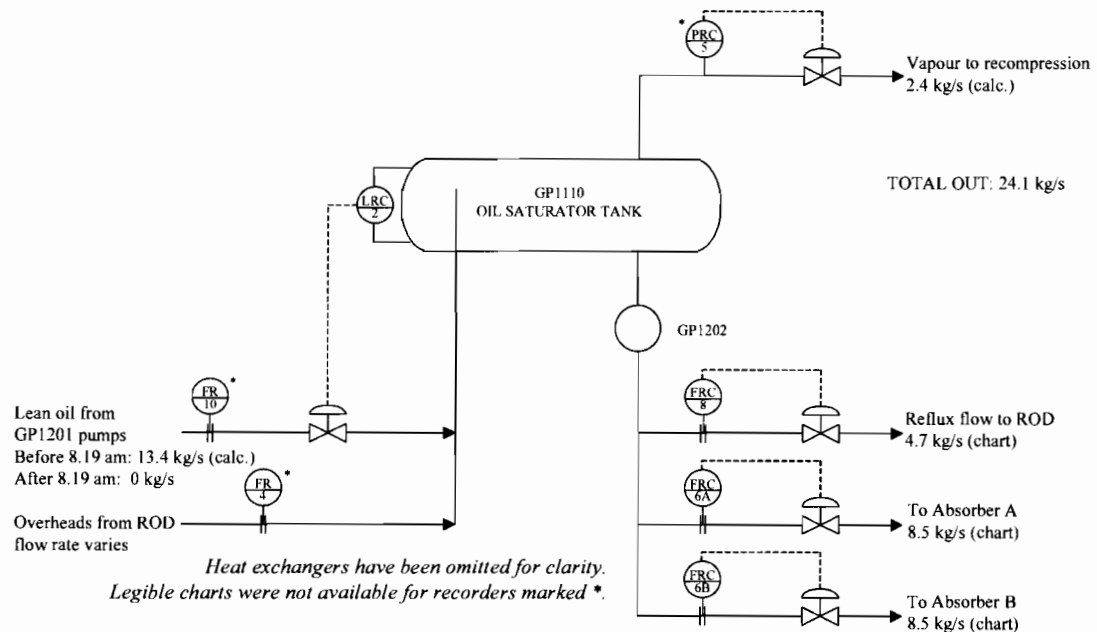
***Figure 5.5 Oil Saturator Tank level and pressure***

5.13 The flows into and out of the Oil Saturator Tank are shown in Figure 5.6. The liquid flow out of the Oil Saturator Tank remained steady at this time, as measured on three of the operating chart recorders. The level increase must therefore have been due to an increase in flow entering the tank. Unfortunately, neither of the two recorders on the incoming streams (FR4 and FR10) were working, so the inlet flows had to be calculated. LRC2 controlled the level in the tank by adjusting the lean oil flow into it, and had been operating effectively up until that time. No fault was found with the LRC2 level transmitter, controller or recorder

that could explain this level rise. It is therefore highly unlikely that the observed rise was due to a controller malfunction.

5.14 A change in controller setpoint by the operator is also considered to be unlikely. The shape of the curve is consistent with an uncontrolled change in level, rather than a move to a new controlled value. The setpoint was found after the accident at 50%, consistent with it not having been changed. Also, the security system records show that the bus conveying the incoming control room operator, Ward, would have arrived at the control room at about 7.03 am, after leaving the gate at 7.01 am. Olsson joined the same bus after handing over to Ward before the bus arrived back at the main gate at 7.10 am. Ward said that he did not make this change, and there is little likelihood that either operator would have made a non-essential controller adjustment at this time.

5.15 The only other source of flow into the Oil Saturator Tank was the overhead line from the ROD (Figure 5.6). It would appear that a higher than normal flow into the Oil Saturator Tank from the top of the ROD must have occurred, which resulted in LRC2 reducing the incoming flow of lean oil. Once LRC2 had closed its control valve as far as possible, it could have done no more to hold the level steady. Continuation of the increased inflow would have resulted in the level increasing above its setpoint, as observed at 7.03 am.

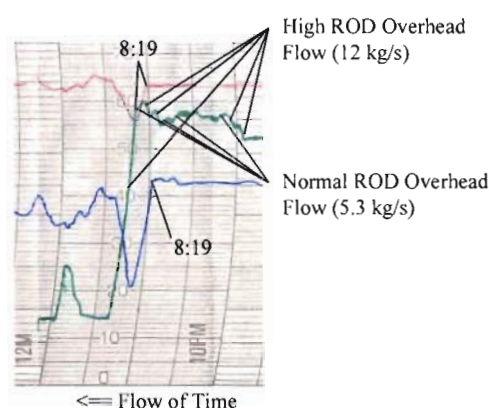


**Figure 5.6 Flows into and out of the Oil Saturator Tank**

5.16 Calculations based on the observed rate of level increase show that the total flow from the top of the ROD at this time was approximately 12 kg/s (equivalent to 840 l/min of condensed liquid), assuming that the control valve for LRC2 was at its minimum position

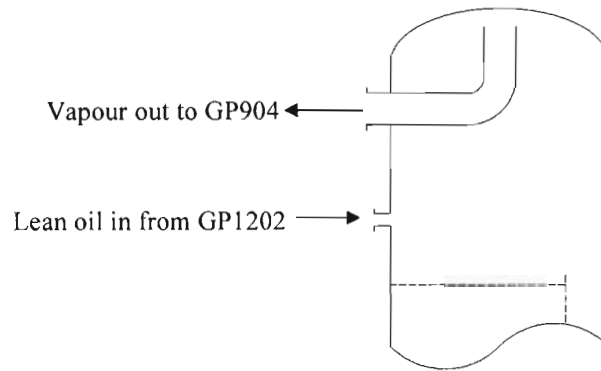


(Figure 5.7). The flow through the control valve was calculated from knowledge of its measured minimum opening when tested, and the system pressures, pump curves and piping configuration. The decreases in level on the same chart correspond to periods of normal vapour flow from the top of the ROD. After the GP1201 pumps stopped at 8.19 am, the rate of decrease also corresponds to an inflow of around 12 kg/s. Therefore this trace is consistent with intermittent high flows of material from the top of the ROD. The observed flowrate is approximately twice the normal vapour flow from the top of the ROD, calculated as 5.3 kg/s. The flow of lean oil to the top of the ROD was measured by FRC8 as 4.7 kg/s. The 12 kg/s overhead flow is therefore somewhat more than the sum of the normal vapour flow and the reflux flow.



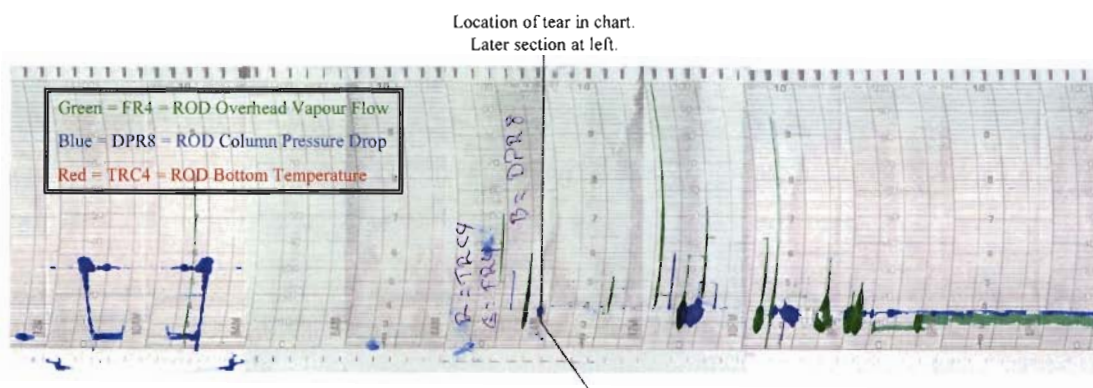
**Figure 5.7 Enlargement of LRC2 trace**

- 5.17 One possible mechanism to explain this is so called “flooding” of the top section of the column. If the flow of vapour rising through a distillation column is excessive, the resulting pressure can prevent liquid flowing freely down the column. This liquid then builds up and will leave by the overhead vapour line, until the downward flow can again be restored. The ROD column does not appear from the drawings to have been fitted with a mist eliminator, which is designed to coalesce small liquid droplets and stop them leaving with the overhead vapour. The outlet connection pointed upward (Figure 5.8) so as to minimise the possibility of liquid slugs entering the vapour line. Although such a design would reduce the impact of some types of liquid carryover, entrainment of small droplets or gross flooding of the top trays could have still allowed liquid to enter the vapour product line.



**Figure 5.8 ROD vapour outlet connection**

5.18 Direct evidence of flooding actually occurring on the morning of 25 September is not available, as the chart recorder for the vapour flow (FR4) was not working. The drive motor was not advancing the chart paper. The same chart (Figure 5.9) also recorded the differential pressure across the ROD (DPR8), a useful indicator of flooding, and the ROD bottoms temperature (TRC4). There is some indication of higher than normal vapour flows and column pressure drops, but the timing of these cannot be determined. The TRC4 trace is not visible. Clearly this chart is of limited use when investigating the events leading up to the accident. A flooding column results in a highly distinctive chart trace, but is difficult to detect from spot indicator readings alone. The poor state of such a critical recorder chart would have made troubleshooting of the ROD column operation virtually impossible from the time that the chart drive failed. As the paper had been wound on at various times, it appears that the operators had used the chart, but the time at which it failed is unclear.



**Figure 5.9 Chart recording of ROD overhead flow (FR4), ROD differential pressure (DPR8) and ROD bottom temperature (TRC4), for which no record is visible**

5.19 According to Shepard, there had been several occasions in the past when the ROD tower had carried over because of “too much cold feed into the tower, particularly if the lean oil itself is more like gasoline than lean oil”. The conditions referred to by Shepard as “too much

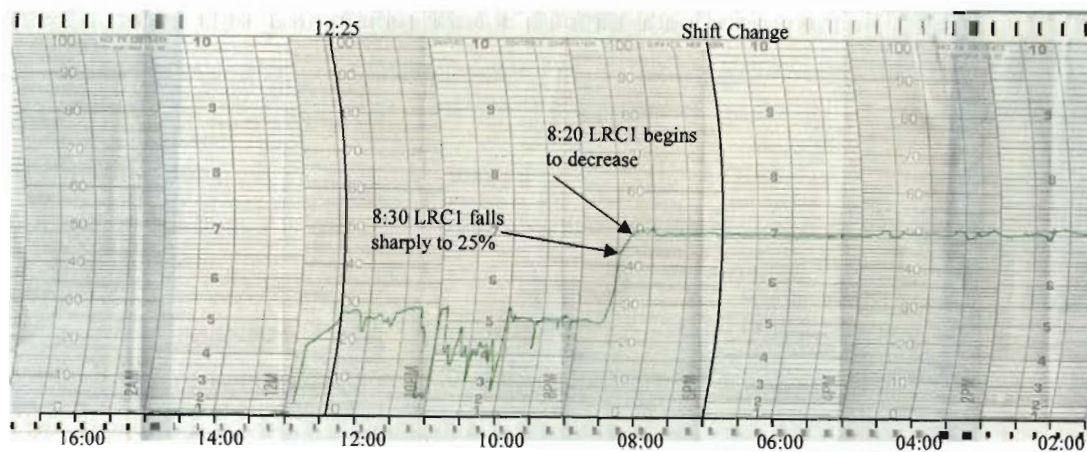
cold feed” and “lean oil more like gasoline” were most likely satisfied on the morning of 25 September. To quantify these effects, the computer simulation was used to calculate the flows into the ROD. A separate detailed computer simulation of the ROD was then used to calculate the internal flowrates and conditions that would have caused the ROD to flood. The flooding calculations were performed using two alternative methods, one from the Fractionation Research Institute (FRI) and the other from the tray manufacturer Glitsch. The results were in general agreement and are summarised in Table 5.1.

**Table 5.1 Results of ROD flooding calculations**

Case	Feed Flowrate (relative to demethanising design case)	Approach to Flooding Limit
7.00 am 25 <sup>th</sup> September 1998	77%	41%
Design Case – Demethanising mode	100%	65%
Design Case – De-ethanising mode	95%	76%
7.00 am 25 <sup>th</sup> September plus 90% more Condensate and -4.5°C feed temperature	109%	89%
7.00 am 25 <sup>th</sup> September plus 40% more Condensate and 40% more Lean Oil and -20°C feed temperature	107%	80%

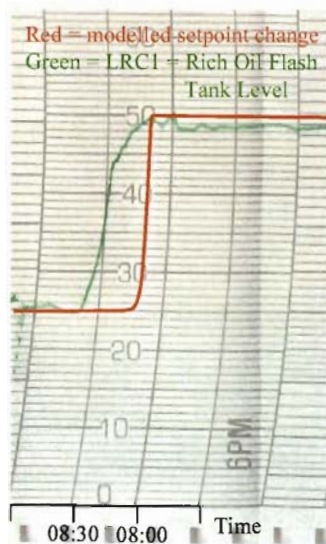
5.20 A 40% increase in the continued flow of condensate and rich oil plus a decrease in feed temperature to -20°C was required to cause flooding, according to these calculations. The steady state feed conditions on the morning of 25 September were not in themselves sufficient to give rise to the extreme conditions required to cause flooding of the ROD. There appear to be two reasons for this. The ROD was designed to remove ethane in addition to the methane it was removing on 25 September. The vapour flowrates required for demethanising alone are lower than those for de-ethanising, and are therefore further away from the column’s flooding limit. Secondly, as more cold feed entered the column, the required heat input for vaporisation in GP905 increased. This heat came from the lean oil. On 25 September the lean oil flowrate was set (on FRC6A and B) at 75% of the Hudson design flowrate. This limited the amount of heat available to vaporise the incoming cold condensate, and in turn limited the amount of vapour that could be generated to well below that required to cause flooding. It therefore appears that some additional factor must have been present to cause the ROD to carry over before 7.00 am on 25 September 1998.

- 5.21 Damage to the column internals is one such possibility. The column was inspected internally following the accident, and the internals of the bottom section of the column were found to have been badly damaged. However, this damage was consistent with rapid depressurisation when GP905 failed. Pre-existing damage to the ROD internals would not have been evident, and therefore remains a possible contributor to the ROD flooding.
- 5.22 A sudden change in the feed flowrate to the ROD could also have precipitated flooding. One such potential change is a sudden decrease in the setpoint of LRC1. Indeed, the setpoint was found to be at 57% after the accident, rather than the 50% expected if it had been left unchanged. A sudden decrease in setpoint would have caused the control valve in the warm feed line to the ROD to have opened rapidly. The level in the Rich Oil Flash Tank did decrease rapidly starting at about 8.20 am (Figure 5.10). Clearly this was too late to be the initiator of the disturbance observed in LRC2 at 7.03 am.



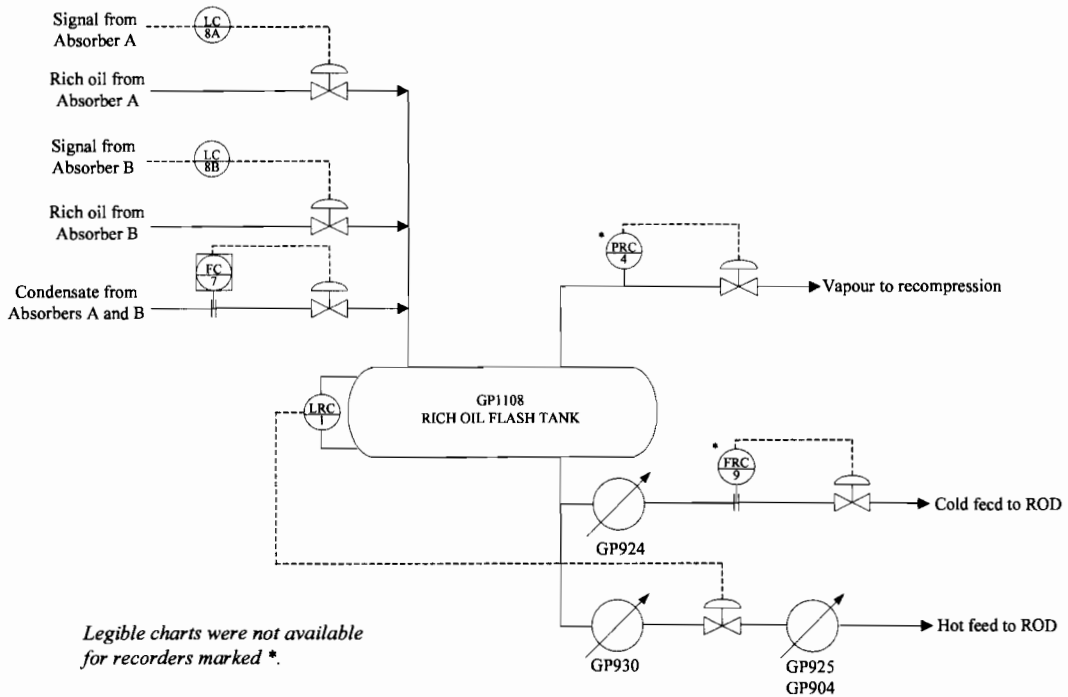
*Figure 5.10 Chart recording of Rich Oil Flash Tank level (LRC1)*

- 5.23 At first sight it appears possible that the drop in LRC1 could have been caused by a change in setpoint. However the panel operator Ward denies making such a change and there appears to have been little reason for him to have done so. The shape of the trace is also contrary to that expected from a change in setpoint, as indicated by the dynamic simulation results shown in Figure 5.11. This simulation used the tested dynamic response of the controller LRC1. This response clearly differs from that observed and supports the view that the level change was not due to a change in setpoint.



*Figure 5.11 Simulated LRC1 setpoint change*

- 5.24 The initial decrease in level at about 8.20 am is thought to have been due to the ramp down in ROD pressure when the GP1201 pumps tripped (Figure 5.5). Controller LRC1 controlled the warm feed to the ROD whereas the flowrate of the cold feed was fixed by flow controller FRC9 (Figure 5.12). The pressure drop across the control valve LRC1 would have increased as the ROD pressure dropped. The flow through the control valve would then have increased too quickly for the LRC1 controller to compensate, and the level would have started to drop. Until 8.29 am, flows continued into and out of the Rich Oil Flash Tank. When the GP1202 pumps tripped at 8.29 am, the flow of rich oil into the Rich Oil Flash Tank ceased and the level dropped more rapidly. This drop in level was due to the continuing flow of cold feed to the ROD through FRC9 and was suddenly arrested when the low temperature shutdown switch, LTSD1, closed the FRC9 control valve in the cold feed line. The calculated rate of heat input through the insulation from the surroundings indicated that LTSD1 would have reset after a time delay of between one and one and a half hours. Some of the later disturbances in the trace are therefore thought to correspond to alternate resetting and tripping of the cold feed trip LTSD1. Matching other features on the chart to those on other charts gives confidence in the timing ascribed to the chart and is consistent with this explanation.
- 5.25 Although a setpoint change to LRC1 remains a possibility, on the evidence available it appears less likely than the above explanation. Such a setpoint change would have resulted in a significant upset to the ROD that could have resulted in carryover or flooding. However, it would have occurred at least one hour after the initial signs of carryover were observed, and so cannot explain the earlier rise indicated by LRC2.



**Figure 5.12 Flows into and out of the Rich Oil Flash Tank**

5.26 Another possible sudden change that could have influenced the ROD was the decision by Ward at 7.30 am to close the TRC3B bypass valve. This would have resulted in a significant increase in condensate flowrate into the rich oil stream. The simulation verified this (Figure 5.4). However, the change in temperature, indicated by TRC3B, also occurred too late to be the initiator of the disturbance in the level indicated by LRC2 which was first seen at 7.03 am.

5.27 In the absence of reliable chart recordings, the precise cause of the high flowrate from the top of the ROD remains unclear. Nevertheless, on the balance of probabilities it appears that the ROD did carry over liquid (or condensable vapour), possibly due to internal flooding. Liquid carryover occurred from some time before 7.03 am until after 8.19 am when the GP1201 pumps stopped, depriving GP905 and the ROD of the heat required for vaporisation.

### **GP1201 PUMPS SHUTDOWN**

5.28 Prior to the level in the Oil Saturator Tank rising at 7.03 am, LRC2 would have progressively closed the level control valve, thereby throttling the flow of lean oil. However, the LRC2 control valve has been found to have remained partly open, even when the signal from the controller was at 0%. It is unclear whether this was a deliberate modification to avoid the shutdown of the GP1201 pumps, or was due to an error in calibrating the control valve positioner. This explains the observed increase in level when

the GP1202B pump was shut down on August 28. On that occasion, while the GP1201 pumps were still on, LRC2 was deliberately closed as far as possible, but the level in the Oil Saturator Tank continued to rise. The resultant flowrate has been calculated to be about the same as the low flow setpoint of LFSD8, which was activated from the same measurement as FR10. The lean oil flow remained above this value for some time, until a disturbance caused the flowrate to dip below the LFSD8 setpoint. LFSD8 then switched off the two operating lean oil booster pumps, GP1201A and B.

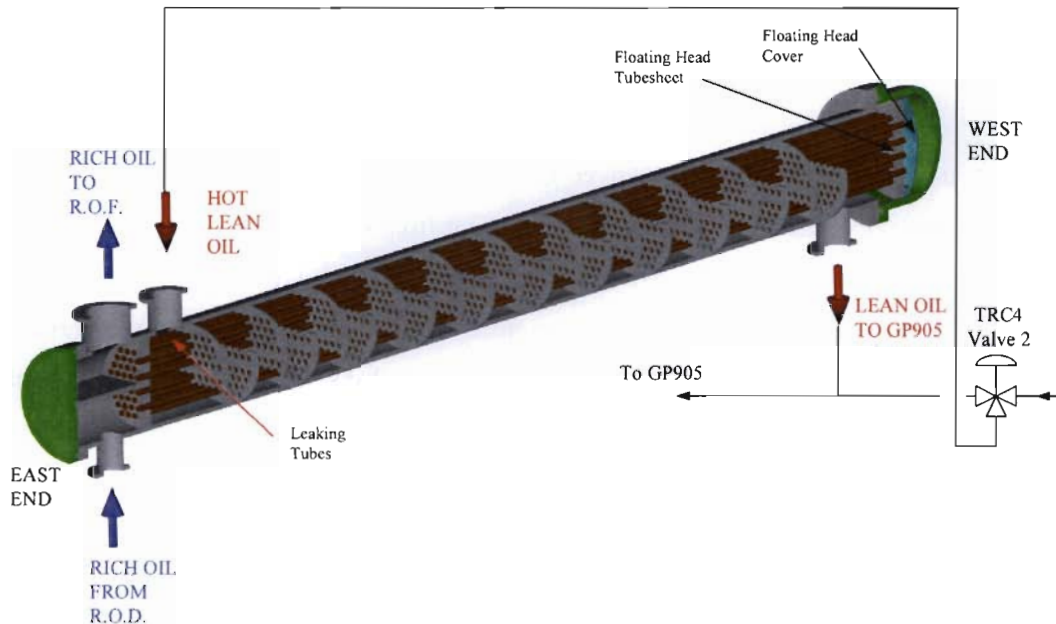
- 5.29 Another postulated cause of the GP1201 pumps shutting down was the failure of one of eight tubes in GP922 (see below). The leak reduced the pressure in the line to the GP1201s. This would have caused the GP1201 pumps to work harder. If the reduction in pressure was sufficient, it could have caused the pumps to trip out on thermal overload. However, hydraulic calculations have shown that, due to the high capacity of the GP1204 pumps, the leak would have resulted in a decrease in flow to the GP1201s of less than 2%. With two GP1201 pumps in operation, there would have been more than sufficient power available to perform the required duty without overload. Also, the metallurgical evidence is that the leaks in GP922 had existed for some months, rather than occurring on 25 September 1998. It is therefore unlikely that the tube failures in GP922 contributed to the stopping of the GP1201 pumps.
- 5.30 Other possible explanations for the GP1201 pumps shutting down include a momentary electrical fault or a blockage. Neither of these explains the increase in level observed in LRC2 and, on the available evidence, both were considered to be much less probable than the above explanation.

### ***HEAT EXCHANGER GP922 LEAKS***

- 5.31 At about 8.30 am it was noticed that the flange at the western end of exchanger GP922 was leaking. A tray was already in place under the leak and a maintenance technician observed it to be one quarter full. Calculations based on the observed leakage rate and the amount of liquid in the tray suggest that GP922 started to leak at about the same time as the GP1201 pumps shut down. The coincidence of the leak of GP922 and the shutdown of the GP1201 pumps suggests that either they had the same cause or were initiated by the same event.
- 5.32 An upset of the ROD has been shown to have been capable of shutting down the GP1201 pumps (see above). Such an upset, in conjunction with the leaks later found in GP922's tubes, could also have initiated the leak of the exchanger flange. GP922 was a floating head exchanger with the rich oil entering and leaving the tube side from the eastern end (Figure 5.13). The outer cover on the western end was in contact with the lean oil on the shell side

at a pressure of about 1,850 kPa. Eight tubes in GP922 failed at some time well before 25 September 1998, but after an internal inspection in October 1996. The tube failure was caused by a combination of erosion and corrosion caused by localised boiling in the hottest part of the top tubes. There was thus a direct path for hot lean oil to enter the rich oil feed to the ROF. When TRC4 valve 2 was directing lean oil into GP922, a portion of the lean oil at a temperature of 270°C was therefore passing directly to the rich oil immediately after entering the shell of the exchanger. In this situation, since the lean oil cooled as it passed through the exchanger, the temperature difference across the west end flange was relatively small.

5.33 However, when the feed to the ROD became cold, the temperature at the base of the column would have fallen. TRC4 would have responded by shutting off the lean oil flow to GP922, and the lean oil would then have entered the shell via the outlet connection, and passed through the broken tubes. In this condition, the west end flange would have encountered the hot lean oil without prior cooling and the temperature difference across the western flange would have been much greater. The combination of a fibre gasket and the detailed design of the flange made it relatively intolerant to such thermal gradients and this change in temperature difference appears to have been the initial cause of the flange leaking.



**Figure 5.13 Heat exchanger GP922**

5.34 The later leaks at the eastern end of the exchanger are considered to have been due to the difference in temperature between the tube inlet and outlet when the flow through the tubes was a small flow of cold condensate rather than the normal large flow of warm rich oil. These leaks of lean oil did not set off the portable gas detectors used by the clean-up crew



after 11.00 am. This implies that the leaking material was predominantly lean oil and it therefore appears that the backflow from the ROD (discussed in detail in paragraphs 5.38 to 5.40) did not reach GP922 at that time. An alternative path for backflow to the ROF existed via the GP1204 seal oil line, which had ample capacity to divert the calculated backflow away from GP905 and GP922. It is also possible that there was insufficient backflow of methane from the top of the ROD to break through the cold lean oil in GP905. This unsaturated lean oil would have absorbed methane and effectively blocked the backflow past that point. It is also possible that the non-return valve may have closed properly during one of the restart attempts during the morning, halting the backflow.

- 5.35 In summary, the initial leak of GP922 at the western flange was probably due to the change in thermal gradient when TRC4 bypassed the exchanger. Later leaks were caused by vertical temperature gradients at the eastern end. Both types of leak were exacerbated by the leaking tubes within the exchanger.

### ***GP1202 PUMP SHUTDOWN***

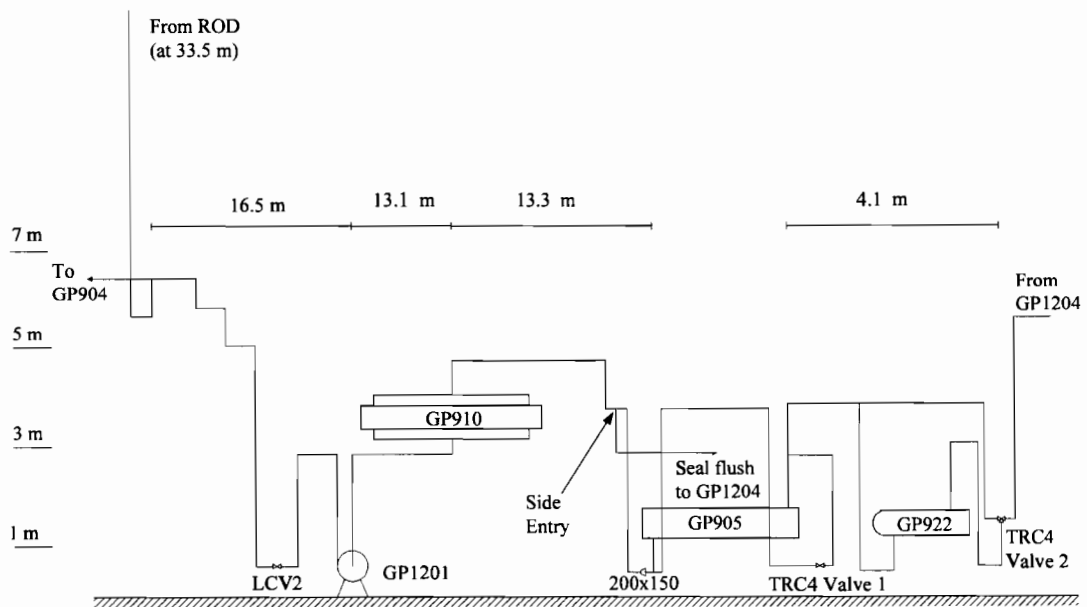
- 5.36 After the GP1201 pumps shut down, GP1202 was still pumping from the Oil Saturator Tank to the two absorbers and to the top of the ROD tower. It quickly drew down the liquid in the tank and was shut down by the low level shutdown switch on the tank, LLSD2, at approximately 14%. This level was consistent with the tested setpoint of LLSD2.
- 5.37 Without any lean oil feed from the GP1201 pumps, the level in the Oil Saturator Tank increased slightly to 15% over twenty minutes from 8.30 am. Following recovery of pressure in the ROD at 8.45 am, the vapour from the ROD displaced enough liquid from the lean oil system (especially exchangers GP904, GP924, GP925 and GP930) to raise the level to 25%. This was sufficient to re-close LLSD2 and allow Rawson to restart GP1202 at about 9.05 am. The level in the Oil Saturator Tank then fell sharply to about 14%. The GP1202 pump was again stopped by the low level shutdown switch and the level remained steady until some ten minutes later when it fell to 9%. This last drop in level was caused by a second attempt to restart GP1202. Despite the low level shutdown switch, the pump continued to run, and presumably lost suction when the level fell too low. It appears that there were some loose wires in the GP1202 motor control rack that prevented the circuit breaker from actuating. The pump became very hot and Visser was eventually able to shut it down by manually opening the circuit breaker shortly before 10.24 am.

### ***GP1201 ATTEMPTED RESTARTS***

- 5.38 The GP1201 pumps tripped at 8.19 am. As already observed in Chapter 3, at 8.29 am the area operator, Ron Rawson, was asked by Ward to restart them but was unable to do so. Rawson stated that all three pumps failed to respond when he depressed the start buttons installed at the pumps. He also observed ice on GP1201A at about 8.45 am. Rawson said he made several more unsuccessful attempts to restart the pumps between 8.30 am and 10.30 am.
- 5.39 The ice seen on the discharge pipe of GP1201A at 8.45 am suggests that the contents of that pump were much colder than normal. When the pump shut down at 8.19 am, the lean oil temperature at the pump was about 28°C. Flashing of this material, if the pump depressurised, would not cause the cooling observed. For the contents to cool below 0°C, a flow of cold material must have occurred. This could not have come from the pump suction line as the pressure gradient would not have allowed flow in that direction. The pressure at the pump discharge, set by the pressure in the ROD (2700 kPa), was above the GP1204 discharge pressure (1850 kPa) which determined the GP1201 suction pressure. Once the GP1201s had stopped, forward flow through them would therefore have been impossible. However, if the non-return valve on the discharge of the GP1201A pump was stuck partially open, reverse flow through that pump would have been possible. Cold material could then have flowed from the top of the ROD, displacing the liquid in the pumps' discharge line and lowering the temperature below 0°C. The flow of vapour calculated to be required to displace the contents of the line by 8.45 am was 45 l/s. This flow is greater than would be expected from the tested leakage rates of the non-return valves. A small granule of scale or other solid material, as observed in the shells of both GP905 and GP922, could have been a possible cause of the check valve not closing fully. It should be noted that ice was observed on only one pump. This is consistent with an open flow path through that pump only, as would be expected from a leaking non-return valve.
- 5.40 When the vapour passed through one pump, it would have passed into the suction line of all three pumps. Any attempt to start them in this condition would have caused the pump motor to rotate only while the start button was depressed. When the start button was released, however, the pump motor would have been tripped by the low flow shutdown switch LFSD8 and the pump would have slowly decreased in speed. This is not in accord with Rawson's evidence as he stated that the pumps did not rotate when the start buttons were pressed. It is possible that Rawson did not recall the manner in which GP1201 failed to start. He may have confused it with his attempts to start GP1202 later in the morning, when the low level shutdown switch LLSD2 would have prevented their rotation.

5.41

In order to start a pump, sufficient liquid must flow into its suction to enable it to prime. The GP1201 pumps were provided with bleed lines to enable small amounts of vapour to be bled from the pump casing to help this. However, this would not have been sufficient if the vapour backflow were continuing or most of the liquid had already been pushed out of the suction line. Two-phase flow calculations showed that the calculated vapour backflow was sufficient to displace all liquid from downward sloping piping. However, the vapour would not have displaced the liquid from the vertical piping legs, but instead would have bubbled through it. The lean oil piping contained many up and down legs (Figure 5.14). In particular, the GP1201 pumps were at one low point in the line and the GP910 cooler was at an adjacent high point. This means that when vapour flowed backwards through the GP1201 pumps it would have displaced most liquid in the discharge line and in the pumps themselves. On the suction side, however, the vapour flow would have supported liquid in the vertical leg and in the GP910 cooler. If the vapour flow were interrupted, this liquid would have fallen back into the pump suction and enabled the pump to start. If more pockets of vapour were drawn into the pump, or through the LFSD8 flow sensor, the pump would then have stopped again. The back flow of vapour could have been interrupted either by closing a block valve on the GP1201A pump, or by the reseating of the check valve, for example, during one of the restart attempts.



(Vertical distances are to scale; horizontal distances are not)

**Figure 5.14 Lean oil piping elevation**

5.42

The evidence before the Commission did not support a finding that the maintenance of the non-return valves was inadequate. A non-return valve is not normally relied upon as a safety feature of a design and it is recognised that a sticking non-return valve is not an

unusual occurrence. Thus the suggestion that the non-return valves were leaking or that one was stuck partially open is not intended to indicate inadequate maintenance.

5.43 An alternative explanation for the difficulty in restarting the first GP1201 pump is that the first pump was overloaded whilst starting. The normal procedure to restart a pump was just to press the start button. Provided one pump was already running, this would have been all that was required to start a second one. When the first pump was started, it would have been delivering through a fully open control valve (LRC2). This would have meant that the pump was delivering the maximum flowrate possible, which could have caused the motor to draw more power than its rated 75 kW. In a short time the pump could then have tripped out on overload. This pump would not have been able to have been restarted until the motor or thermal overload cooled and the overload relay reset. Likewise the other two pumps could have behaved in an identical fashion. In such circumstances it is necessary to partially close the discharge valve in order to start the pump. In common with the vapour lock explanation, this does not accord with Rawson's recollection that the pumps did not rotate. They would have rotated at least briefly. It also does not explain the observed icing of the discharge piping. On the balance of probabilities, the backflow explanation is the correct explanation for what occurred.

5.44 An electrical failure affecting all three GP1201 pumps has been postulated to have prevented restart of the pumps as observed by Rawson. However, the only electrical systems that were common to all three pumps were the trip circuits. These were wired in such a way that they would stop each pump when it was running, but would not prevent the pump from rotating whilst the start button was depressed. This theory is thus inconsistent with Rawson's recollection. Also, all but one trip circuit (LFSD8) affected other equipment that continued to run. The fault would therefore have to have been with the LFSD8 trip circuit, and would also have to have cleared to enable restart after 12.00 noon. This does not explain the observed icing, and is considered much less likely than the vapour lock explanation.

5.45 A related scenario is electrical failure of one working pump, followed by the second working pump overheating and tripping out on overload. This could have prevented two of the three pumps from starting when Rawson made the initial attempt. However, the standby pump would still have been able to rotate and it is likely that the thermister that tripped the first pump would have reset during the ten minutes or so between the trip and the restart attempt. Also, it should have become apparent during the subsequent restart attempts during the morning that only one of the pumps was defective. This scenario is also considered to be improbable.

5.46 A further possibility is that either the operator did not attempt to restart the pumps, or if he did so, did not hold down the start button for sufficient time for the pump to prime. It is highly unlikely that he did not attempt to restart the GP1201 pumps, as he would not have observed the ice on the discharge line of the pumps if he had not been present at the pumps. The need to restart them was clearly evident, even if the urgency to do so was not. The need to start a GP1201 pump with no other GP1201 pump running was rare and normally only occurred after a planned shutdown. When a spare pump was started whilst another was already running, the start button needed only to have been pressed briefly, as the low flow shutdown switch would already have been satisfied. When starting the first pump when all were off, it would have been necessary to hold down the start button for a sufficiently long time for the flow to build up and satisfy the low flow shutdown switch LFSD8. It is possible that this was not done, particularly if some vapour pockets existed requiring the button to be depressed for more than a second or two.

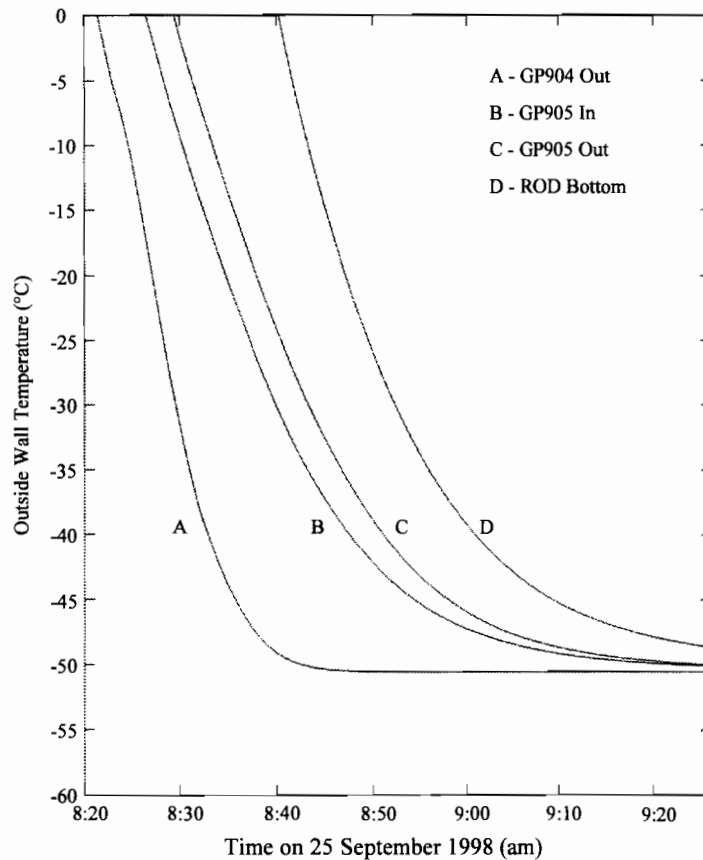
5.47 On the balance of probabilities, the most likely reason that the GP1201 pumps could not be restarted was that they were vapour locked due to a flow of vapour back from the ROD through a partially open non-return valve. Whatever the restart process followed by Rawson, it was not successful in removing this vapour from the pumps and other parts of the lean oil system.

### ***COOL DOWN***

5.48 Even though the lean oil flow ceased at 8.30 am, the flow from the absorbers through the Rich Oil Flash Tank to the ROD continued for most of the morning until the gas flow into the plant was cut off at about 11.00 am. The composition of the flow from the absorbers through the leaking FRC7 valve was that of condensate. In the absence of lean oil, the material flowing out of the rich oil trap tray to the Rich Oil Flash Tank via LC8A and LC8B was entrained condensate that had been coalesced by the absorber trays. This would have greatly increased the volatility of the fluid flowing to the ROD at the same time as the total flowrate decreased. Simultaneously, the heat input to the ROD feed from the lean oil was lost.

5.49 Before the shutdown of the GP1201 and GP1202 pumps, the temperature in the Rich Oil Flash Tank was about -33°C. After the pumps stopped, the contents of the Rich Oil Flash Tank cooled down rapidly to -42°C and both feeds to the ROD cooled to -48°C. The dynamic modelling of the system shows that within half an hour the entire ROD, including its feed piping, and GP905 were at -20°C and after an hour had cooled to -48°C (Figure 5.15). They remained at about this temperature for the rest of the morning.

5.50 The results in Figure 5.15 are conservative and assume that the high level in Absorber B was not sufficient for the direct overflow of condensate into the rich oil trap tray. If the condensate continued to overflow after 8.30 am, the times in Figure 5.15 could be as little as half those indicated.



**Figure 5.15 Thermal response of GP904, GP905 and ROD following loss of lean oil**

5.51 The exchanger GP905 was thus maintained at a temperature of  $-48^{\circ}\text{C}$  from before 9.30 am. The only possible flow of hot oil through this exchanger during the next two and a half hours was the small flow of seal flush oil that recirculated from the GP1204s through GP922 and GP905 before branching off the main line and flowing back to the GP1204 seals. This total flow was 12 l/min per pump or 36 l/min if the seal flow was active for all three pumps. This flowrate has been calculated to be insufficient to change the temperature of GP905, or cause sufficient stress at the weld to initiate failure. The continuing flow of cold condensate down the ROD was more than sufficient to replace any condensate that was boiled off due to the heat input from the seal oil. It is also possible that the reverse flow described above could have prevented even this small flow of hot oil. In any event, the flow of seal oil ceased when the GP1204 pumps were shut down by Visser at 11.10 am.

## ***GP905 FAILURE***

- 5.52 As the morning progressed, the leakage at the flanges of GP922 was receiving attention from more and more people. As already observed in Chapter 3, Vandersteen and Knight, who had been retensioning the bolts on the GP922 flanges, finished their work at about 12.15 pm without making any significant changes to the bolt tensions or the rate of leakage. It was at about this time that the decision was made to re-introduce lean oil flow into GP922 to try and stop the leak.
- 5.53 By then, GP905 was at  $-48^{\circ}\text{C}$  with a small flow of condensate through the tube side. The shell side was either full of cold lean oil or contained lean oil with some vapour above it. There was no seal oil flow by this time, so that the shell side was essentially static. Clearly GP905 had not failed due to low temperature alone during the preceding two and a half hours. This is consistent with the metallurgical evidence (see Chapter 6) that additional thermal stresses were required to initiate failure.
- 5.54 The GP1201 pumps could only be started if the GP1204 pumps were running, as the low flow shut down switch LFSD7 in the oil line to the ROF heaters GP501A and B was also wired into the starter circuits for the GP1201 pumps. Unless LFSD7 was closed by a flow of oil from GP1204 through the heaters, the GP1201 pumps were unable to run. The GP1204 pumps were eventually started successfully at 12.11 pm, after resetting some low flow shutdowns on the flow control valves to the heaters. Heath Brew, directed by the day supervisor Ian Kennedy, attempted to start a GP1201 pump at about this time. Although he thought the attempt was successful, the pump did not generate flow observable in the control room, and the pump was found to have stopped when he returned to it a few minutes later. A second attempt was made to start a different GP1201 pump shortly after 12.15 pm and by 12.17 pm this was thought by those in the field to have been successful. However, no change was observed in the Oil Saturator Tank level, LRC2 (Figure 5.5). It is likely that vapour from the ROD had displaced liquid from the heat exchangers GP930, GP925, GP904 and GP924. The time required to refill these exchangers has been calculated at up to 15 minutes, depending on the flowrate, so that an immediate increase in level would not have been apparent.
- 5.55 What followed has already been discussed in Chapter 3. At 12:20:52, following the attempt to reintroduce lean oil circulation, the production co-ordinator, Shepard contacted Ward by radio in the control room. He asked Ward to close TRC4. Ward mistakenly understood the reference to be PRC4 rather than TRC4. Beside GP922, Shepard waited to see TRC4 Valve 1 open, but nothing happened. Ward then reported to him that the PRC4 controller had no

output i.e., it was already closed. Shepard heard Ward to say that the TRC4 controller had no output.

5.56 Shepard then asked Ward to open TRC4 to 100%. It was at about this time that Shepard operated the HS4 switch changing the operating mode of TRC4 from demethanising mode to de-ethanising mode.

5.57 With the very low temperatures in the bottom of the ROD tower at this time, the output of the TRC4 controller would have been 100% (15 psi). In this condition, and with HS4 in its normal position for demethaniser mode, the two control valves would have been set for the flow path shown in Figure 5.16. Changing the switch to de-ethaniser mode would then have changed the flow path to that shown in Figure 5.17. As a result, lean oil would have bypassed both heat exchangers, although a small flow would still have passed through GP905, provided that at least one GP1201 pump was operating.

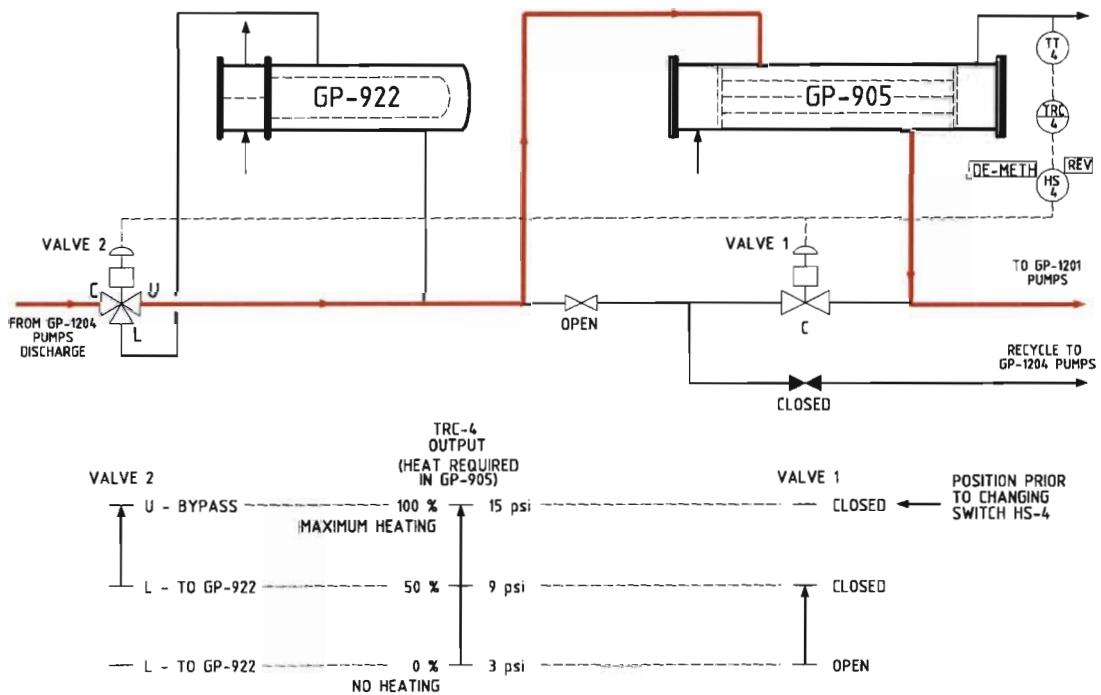


Figure 5.16 Flow path prior to changing HS4 from demethaniser mode



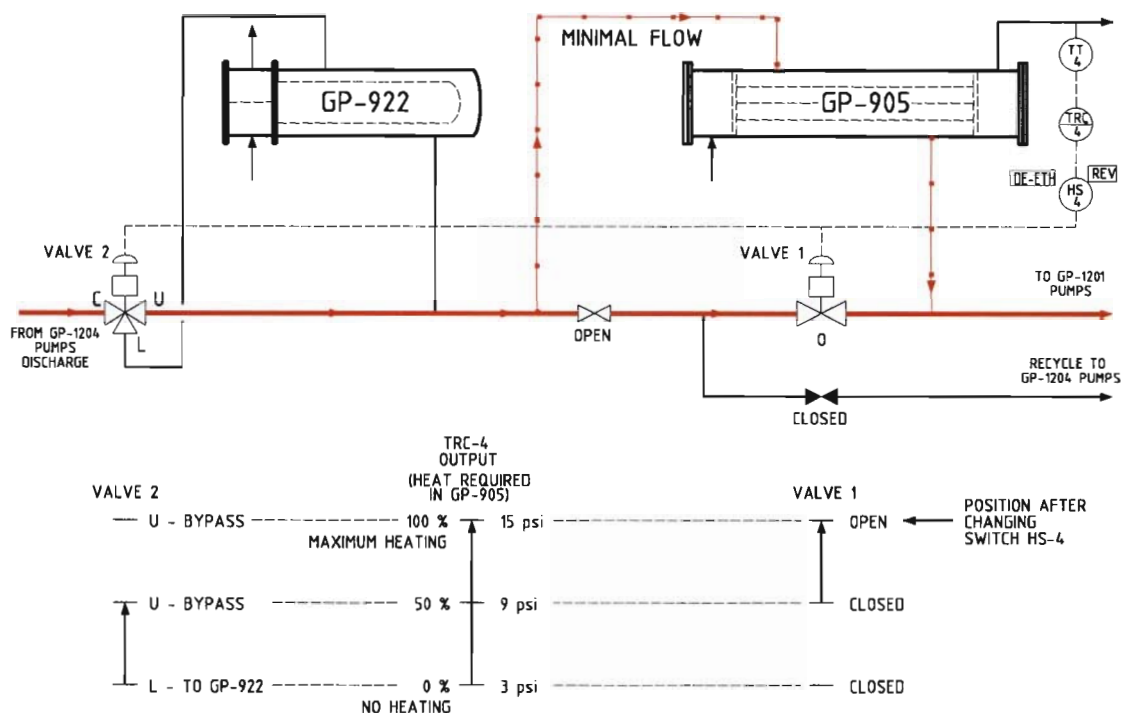


Figure 5.17 Flow path after HS4 was changed to de-ethaniser mode

- 5.58 Shepard said that moments before the accident he observed the stem of TRC4 valve 1 rising indicating that the valve was opening. It is not clear whether this was correct. However, if TRC4 Valve 1 did begin to open as Shepard said it did, it would, as it opened, have reduced rather than increased the flow of lean oil through GP905. It would not, therefore, have caused GP905 to fail.
- 5.59 In any event, almost immediately after Ward opened PRC4 to 100%, GP905 ruptured.
- 5.60 Ward then closed PRC4. This was the state in which it was found after the accident. PRC4 controlled the back pressure on the Rich Oil Flash Tank and would have had no effect on the conditions in GP905 or on the TRC4 valves or any other equipment in the immediate ROD area.
- 5.61 The metallurgical evidence concerning the failure of GP905 shows that the exchanger would not have failed solely due to reaching a temperature of  $-48^{\circ}\text{C}$  (see Chapter 6). As discussed above, GP905 reached  $-48^{\circ}\text{C}$  by 9.30 am and yet it did not fail until 12.25 pm. There needed to be an additional stress on the channel weld to cause it to fail. There was no evidence of any mechanical impact in that area, which was, in any case, covered by insulation. Finite element modelling of the stresses in the exchanger showed that a sudden increase in the shell-side temperature, as would occur with re-establishing flow through a GP1201 pump, would produce sufficient thermal stress to cause the exchanger to rupture.

No other credible sources of additional stress were found. As the hot lean oil in the ROF was the only source of heat which could be applied suddenly to GP905 and the process personnel were attempting to re-establish this flow, it appears to have been the source of the additional stress.

5.62 For a significant flow of lean oil to have entered GP905, a GP1201 pump must have been restarted, and it appears highly likely that the second attempt at about 12.15 pm was at least partially successful. As discussed above, to restart a pump that had been vapour locked, some action must have occurred to fill the pump casing with liquid. This occurred either by an operator closing a discharge valve on the GP1201A pump thereby stopping all reverse flow, or by the non-return valve reseating, probably earlier in the morning. This would have allowed the lean oil held up in GP910 to flow down the line to the pumps while the methane flowed up the line to GP910 (see Figure 5.14). Once the liquid and gas settled out, the pump would have been primed and could have been restarted. However, it is possible that pockets of vapour remained in the piping, and it is quite plausible that once started, the pump would have stopped again after a short while. There is evidence that the GP1201 pump started at about 12.12 pm but only ran for a minute or two, if at all. The time for which the pump ran the second time just prior to 12.17 pm cannot be determined with any precision. However, it is clear that it must have run for sufficient time to allow some hot lean oil to enter GP905.

5.63 For a significant flow of lean oil to have entered GP905, a GP1201 pump must have started. Once one GP1201 was started, any action taken with TRC4 or HS4 was too late. If the strategy were to be effective in limiting the rate of temperature rise within GP905, these valves should have been correctly aligned before starting a GP1201 pump. The action taken by Ward in opening PRC4 for less than a minute could not have had any bearing on the failure of GP905. There was insufficient time for any resultant pressure decrease in the Rich Oil Flash Tank to have any impact on conditions in the ROD and GP905. This is confirmed by the strip chart showing the ROD pressure (Figure 5.5). GP905 did not fail immediately the GP1201 was started because of the time required to heat the tubesheet in GP905. Dynamic finite element stress analysis of the tube sheet has shown that the time required for the stresses to reach the failure level was consistent with the observed delay. GP905 failed because of the combination of low temperature due to the earlier loss of lean oil circulation and the subsequent re-introduction of hot oil following restart of one GP1201 pump.

## ***SUMMARY OF TECHNICAL FINDINGS***

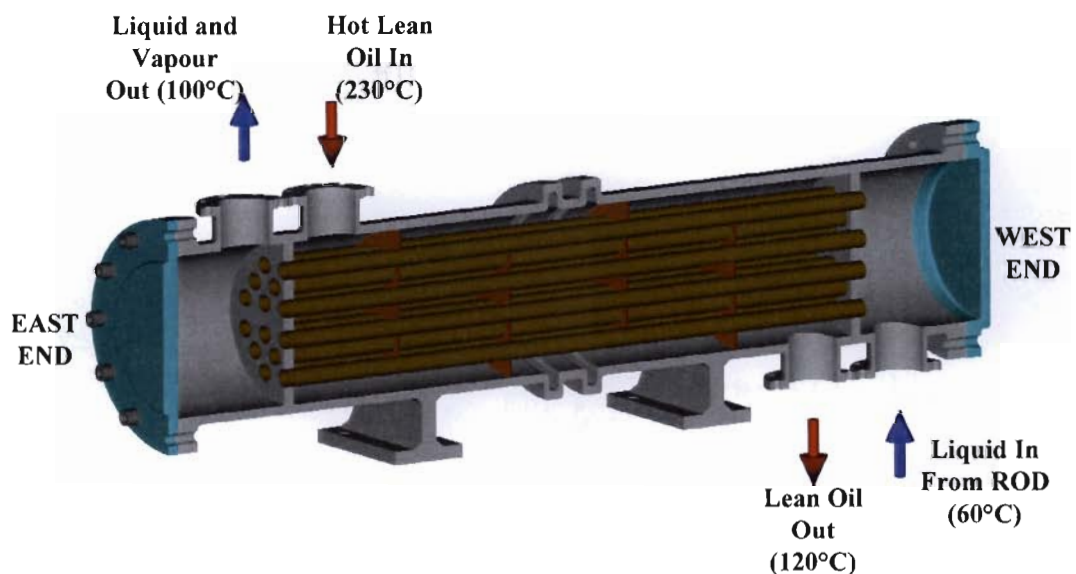
- 5.64 The events overnight on 24 and 25 September and during the early morning of 25 September resulted in cold condensate overflowing from the bottom of Absorber B into the rich oil stream to the Rich Oil Flash Tank. This resulted in a decrease in temperature in the Rich Oil Flash Tank, but, provided lean oil circulation continued, did not present a major problem. Some time prior to 7.00 am on 25 September, the ROD began to carry over additional material into its vapour line. It is likely that this was entrained liquid. The cause of this carryover has not been identified. It is known that in the past, excessively cold and light feed to the ROD has caused flooding, but the mechanism by which this occurs is unclear. Simulation shows that if the ROD internals were intact, the operating conditions on the morning of 25 September were a long way from the column's flooding limit. Although the exact mechanism of carryover is unclear, it is highly likely that carryover was the cause of the GP1201 pumps shutting down.
- 5.65 Once the level controller on the Oil Saturator Tank could not close its control valve any further, the level increased significantly. The discharge flowrate of the GP1201 pumps had been reduced to near to the low flow shutdown point, and eventually dipped below this trip point, causing the GP1201 pumps to shut down. The non-return valve on GP1201A stuck partially open, allowing cold vapour to flow back through the pump into the lean oil circuit. This vapour made restart of the pumps difficult until the flow from the ROD was interrupted during one of the restart attempts. Liquid then flowed back through the line from the elevated GP910 exchanger into the pump suction enabling the pump to be started. Residual vapour in the line continued to interfere with reliable pump operation.
- 5.66 By 9.30 am the ROD and its reboiler, GP905, had cooled to about  $-48^{\circ}\text{C}$  under the influence of a continuing flow of cold, flashing condensate from the absorbers in the absence of heating from the lean oil. When one GP1201 pump was eventually started around 12.17 pm, some hot lean oil entered the shell of GP905 and started to supply heat. As the tubesheet warmed up from its previous low temperature, the stress in the circumferential channel-to-tubesheet weld increased until at 12.25 pm the weld cracked and the exchanger failed catastrophically.

# Chapter 6

## THE METALLURGICAL ANALYSIS OF GP905

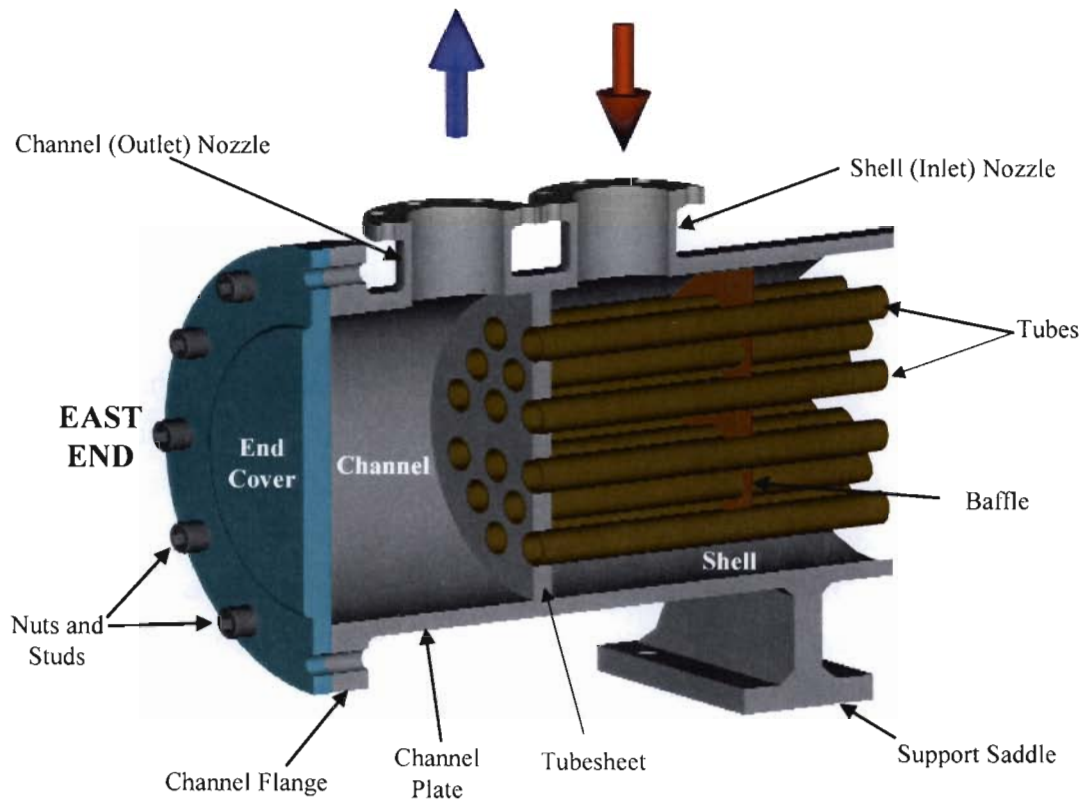
### *THE GP905 REBOILER*

- 6.1 The GP905 reboiler was a single tube-pass shell and tube heat exchanger. See Figure 6.1. Cold ROD tower liquid (demethanised rich oil) entered the channel at the west end and was heated, by the hot lean oil on the shell side, as it passed through the tubes to the east end. It left the east end channel as a mixture of warm liquid and vapour, and returned to the bottom of the ROD. The hot lean oil entered the reboiler's shell at the east end and was cooled as it flowed round the baffles to the west end. It flowed in the opposite direction to the liquid in the tubes. The temperatures marked on Figure 6.1 were typical of those for normal plant operations. They are not the temperatures existing on 25 September 1998.

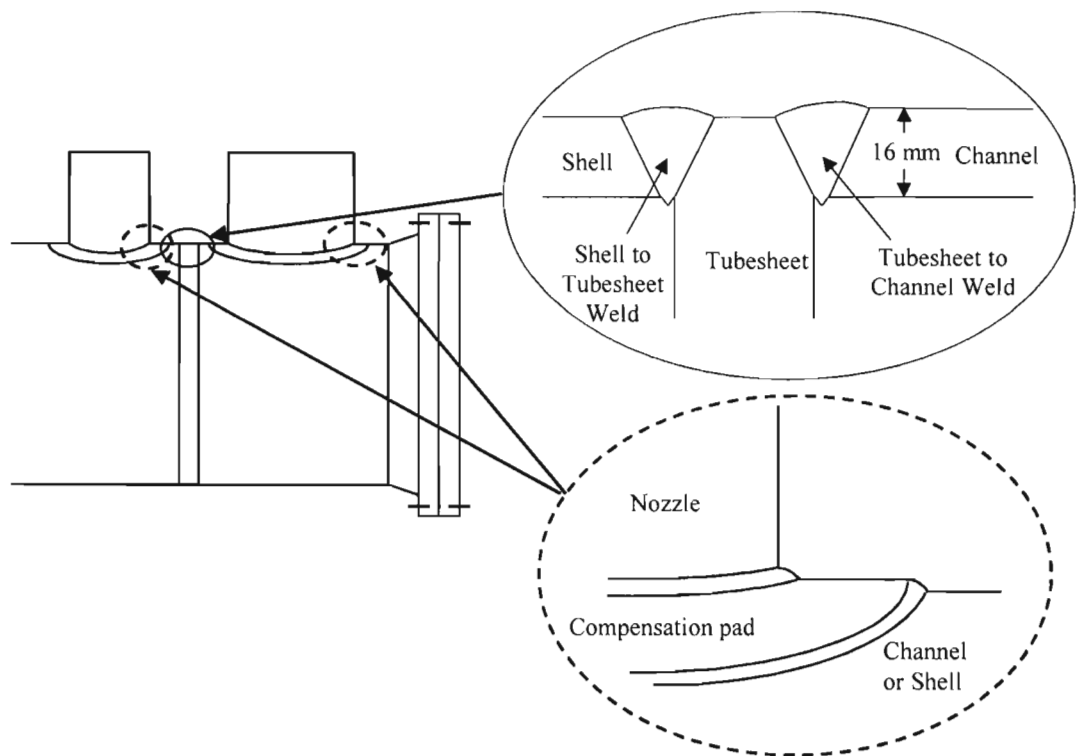


*Figure 6.1 Schematic view of the GP905 Reboiler*

- 6.2 The different parts of an exchanger have specific names. These are shown in Figure 6.2.
- 6.3 Figure 6.3 provides details of the welds that attached the reboiler's shell to its tubesheet and its tubesheet to its channel. The figure also provides details the reboiler's nozzles.



*Figure 6.2 Naming convention used for exchanger parts*



*Figure 6.3 Details of tubesheet welds and nozzle attachments*

## ***FORENSIC STUDY OF THE FRACTURE SURFACE***

- 6.4 The ruptured portion of GP905 was subjected to a detailed examination and a number of metallurgical tests. The aim of this work was to learn the mechanism of failure from inspections of the failed surface and from mechanical tests on the metal of the vessel.
- 6.5 It was found that the origin of the failure was in a weld between the channel and tubesheet at the east end of GP905. It was a brittle fracture, with localised ligament failures. The indications were that the failure occurred at a low temperature that was well below the normal operating temperature for the vessel.
- 6.6 An inspection and test programme was developed. As the work progressed, the programme was modified and extended to encompass current findings. The programme included:
- **A visual examination** - to identify the extent of damage, type and mode of fracture, the origin (or origins) of the fracture, and features which contributed to the fracture.
  - **Radiography, magnetic particle inspection and ultrasonic** (non-destructive) tests - to identify, for specific parts of the failure surface, the type and extent of flaws.
  - **Metallography inspection** (optical microscopy of metal grain structures) - to identify the crack's path, characteristics of the flaws and fracture's origin, and for material verification.
  - **Scanning electron microscope inspection** - to assess the microstructure of the failure surface and to assist in establishing the fracture's origin.
  - **Fracture toughness testing** - to determine how temperature affected the characteristics of the fracture surface, the fracture mode and the metal's toughness.
  - **Chemical analysis, tensile testing and Charpy impact testing** - for material verification.
  - **Residual stress measurement** - to determine the residual stress at the critical location for input to the failure analysis.
- 6.7 Figure 6.4 is a photograph of the failed (east) end of the GP905 reboiler and Figure 6.5 is a simple diagram showing the location of the crack. The origin of the fracture was at the 8 o'clock position in the reboiler's tubesheet to channel weld, when viewed from the east end. It progressed in the weld (in two directions from its origin) until it reached the

10 o'clock and 6 o'clock positions. There it broke into the metal plate of the channel. The visual appearance of the fracture in the weld was essentially that of a brittle fracture.

- 6.8 At the 6 o'clock position the fracture changed direction and broke into the channel. There were several smooth changes of direction before the fracture finally broke through the channel flange just below the 3 o'clock position. At this stage 30 out of the 40 flange studs broke and the channel plate peeled outwards in a clockwise direction. At 10 o'clock the fracture also broke into the channel. It headed towards the outlet nozzle stopping when it reached the nozzle's compensation pad.
- 6.9 The fracture surface for the main crack was generally flat with fine, almost parallel features, and localised ligament tearing. These features indicate the direction of the crack propagation. What the surface shows is explained in Figure 6.6.

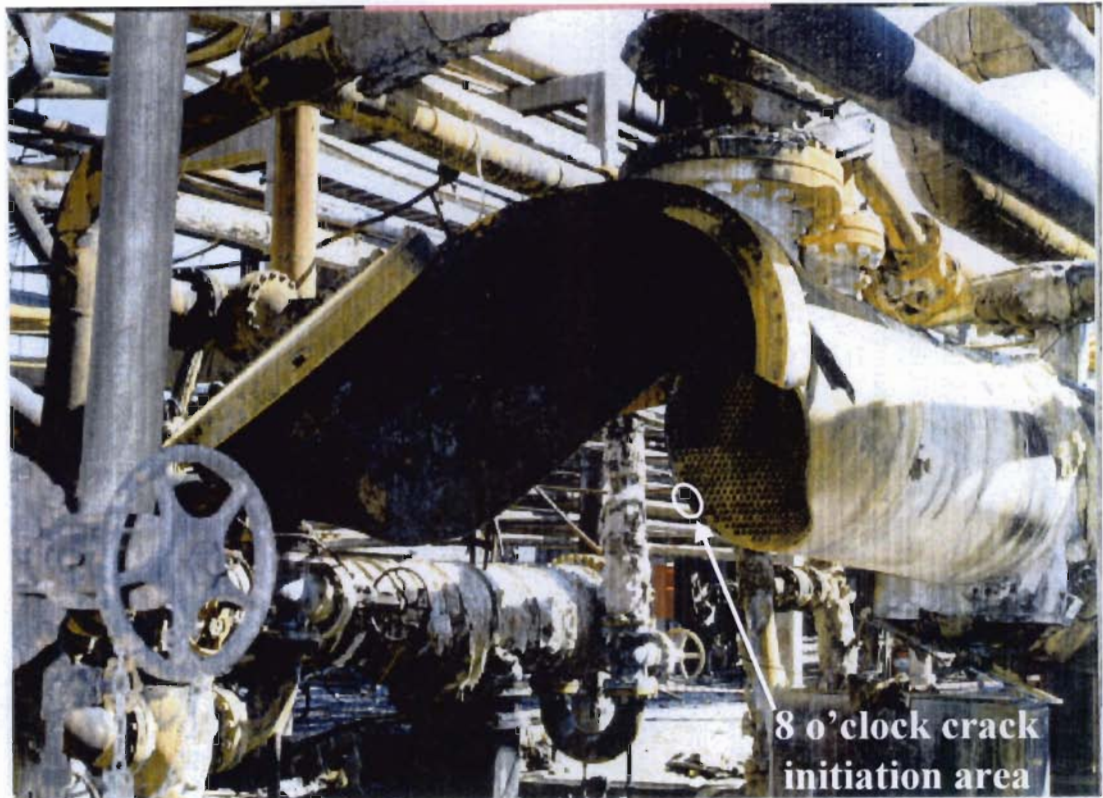


Figure 6.4 Photograph of the failed end of GP905

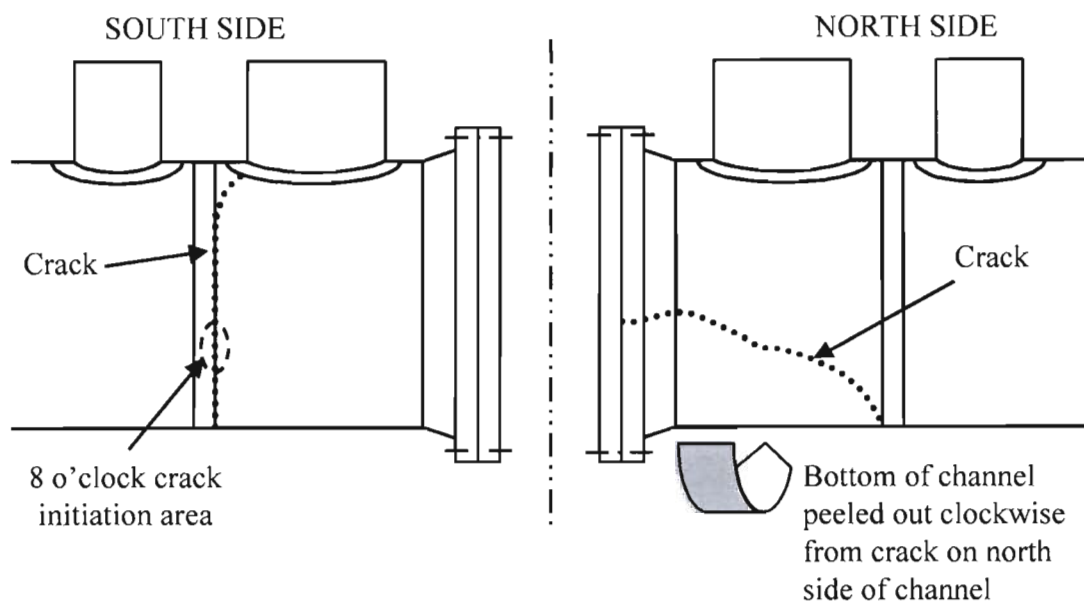
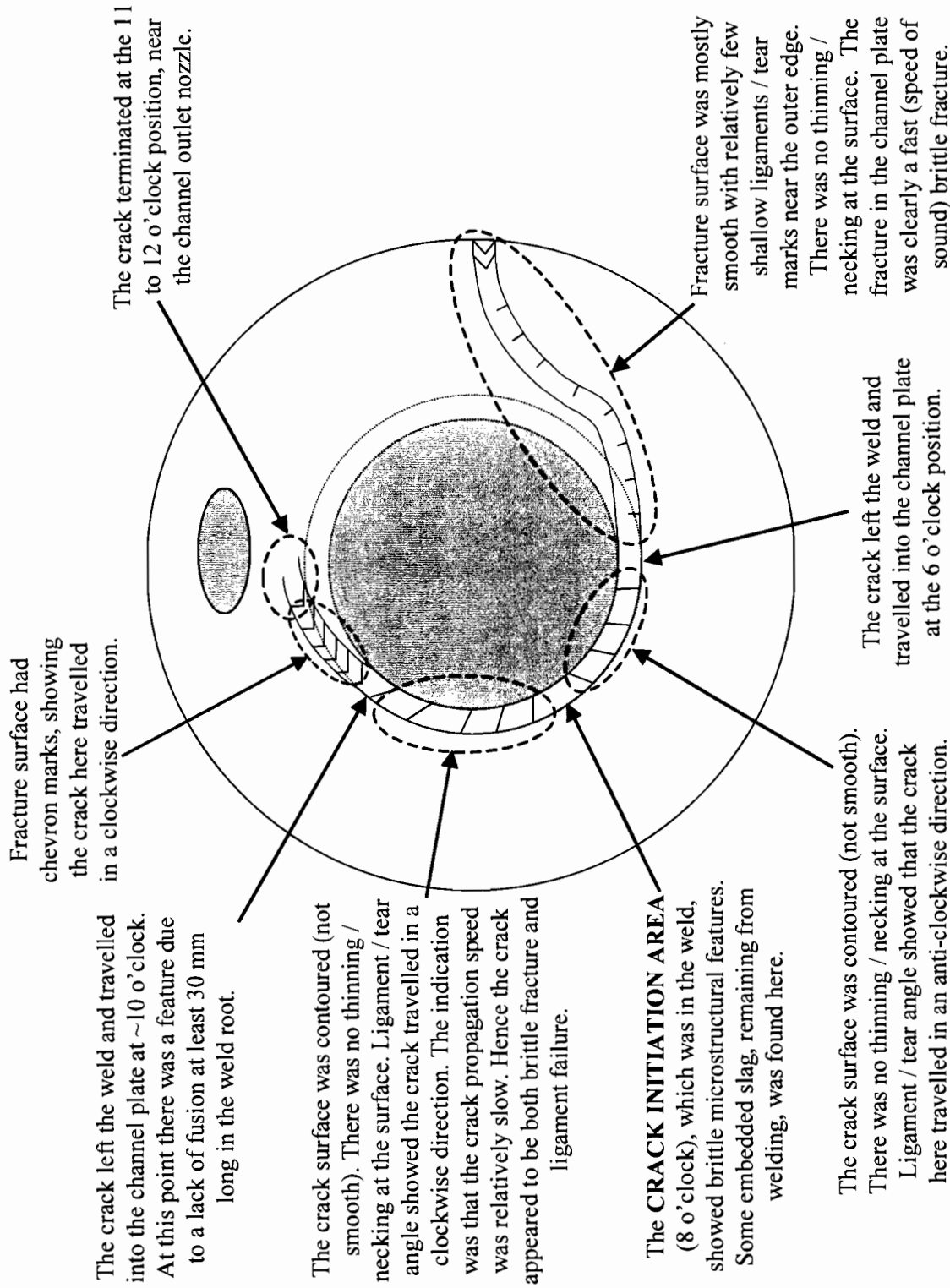


Figure 6.5 Schematic representation of the failure







*Figure 6.6 Visible features of crack as viewed looking into the east end channel*

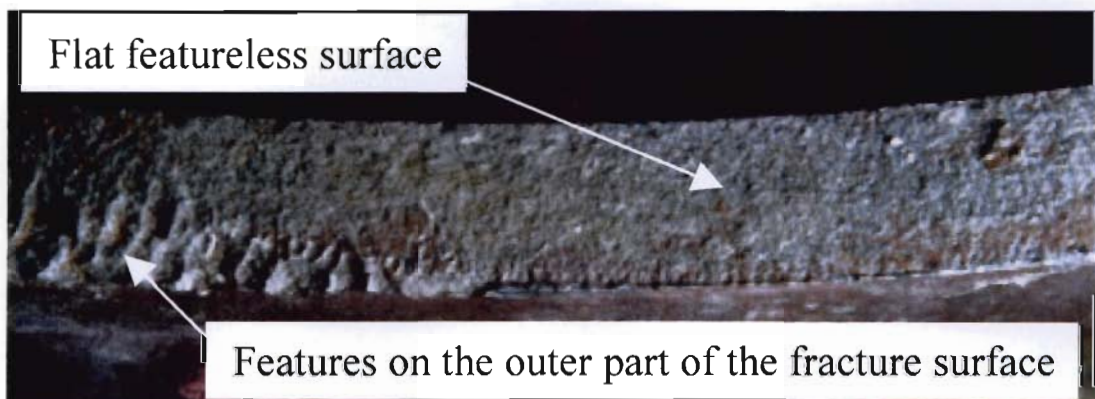
6.10 Near the 8 o'clock and 7 o'clock positions there are features on the surface that are several millimetres in height. These can be seen in Figure 6.7 and Figure 6.8. These large features are called ligaments and are indicative of localised tensile overload. The angle of these ligaments and other surface markings indicate that the crack origin lay in the 7 o'clock and 8 o'clock region. The featured surface and ligaments indicate that the crack propagated slowly while it was in the weld. It should be noted that the term "slowly" is used in a relative sense, and is in contrast to a pure brittle fracture where the crack propagates at the speed of sound (fast) leaving a smooth surface.



*Figure 6.7 Ligaments at the 7 o'clock position*

*Figure 6.8 Ligament at the 8 o'clock position*

6.11 By contrast the failure surface in the channel plate (between 6 o'clock and just before 3 o'clock) is smoother, see Figure 6.9. It is flat and featureless on the inner surface, but has noticeable markings on the outer surface. It can therefore be concluded that the crack's propagation speed in the channel plate was faster than it was in the tubesheet to channel weld. It is concluded that the failure in the channel was fast brittle fracture.

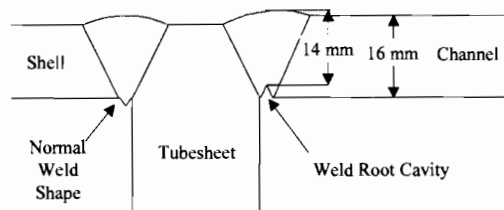


*Figure 6.9 Close-up of the channel's fracture surface (around 5 o'clock)*

6.12 Inspection of the 8 o'clock position identified several features that could individually or together have caused this location to be the crack's initiating point. These were:

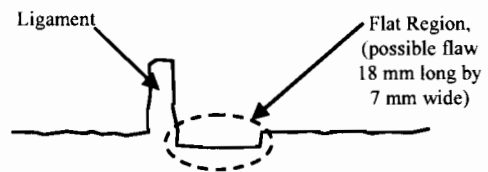
- A weld root cavity.
- A flat region that could have been a pre-existing flaw.
- A large slag inclusion (within the flat region) creating a non-bonded area within the tubesheet to channel weld.
- A slag inclusion creating a non-bonded area at the root of the tubesheet to channel weld.

6.13 The weld root cavity was about 230 mm long and 2 mm deep. It was centred approximately at the 8 o'clock position. It was identified when visually inspecting the failure surface with the naked eye. Figure 6.10 shows a schematic drawing of the weld root cavity in cross section.



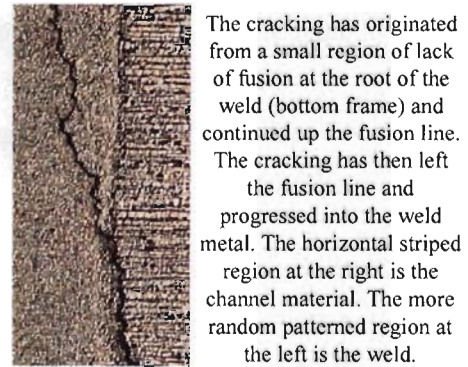
**Figure 6.10 Weld root cavity**

6.14 The flat region is to the left of the ligament in Figure 6.8. This feature, although difficult to see in this photo, is noticeable when inspecting the surface with the naked eye. The flat region is in a different plane to the neighbouring crack surface. The crack's surface primarily runs along the middle of the weld.



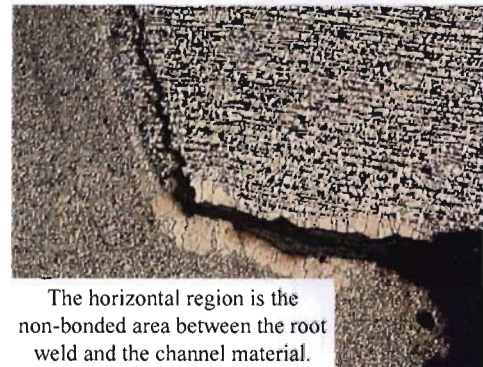
**Figure 6.11 Side view of flat region**

6.15 This flat region is possibly a flaw that existed before 25 September. Flaws of a similar size were found in the tubesheet to channel weld at the west (non-failed) end of the reboiler. Figure 6.12 shows a crack in the west end, producing a similar flaw. This crack originated from a small region of a lack of fusion at the weld root.



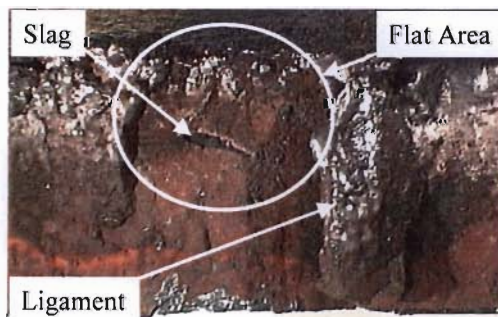
The cracking has originated from a small region of lack of fusion at the root of the weld (bottom frame) and continued up the fusion line. The cracking has then left the fusion line and progressed into the weld metal. The horizontal striped region at the right is the channel material. The more random patterned region at the left is the weld.

6.16 The scanning electron microscope revealed non-metallic inclusions scattered within the 8 o'clock area. On detailed examination of the surface, a large slag inclusion (measuring 5 mm by 1 mm) can be seen in the middle of the flat region. Figure 6.13 and Figure 6.14 are photographs of the surface at the 8 o'clock position before and after cleaning. The slag inclusion is clearly visible. X-ray analysis confirmed the inclusion to be welding slag.

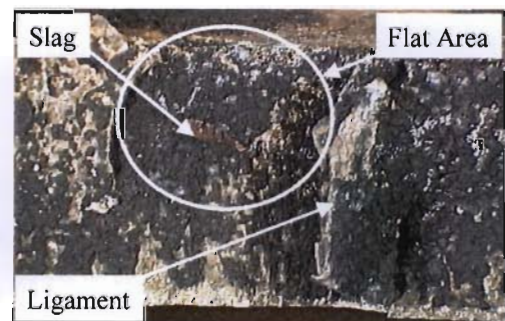


The horizontal region is the non-bonded area between the root weld and the channel material.

**Figure 6.12 Tubesheet to channel weld flaw**



**Figure 6.13 Close-up of the 8 o'clock position (before cleaning the surface)**



**Figure 6.14 Close-up of the 8 o'clock position (after cleaning the surface)**

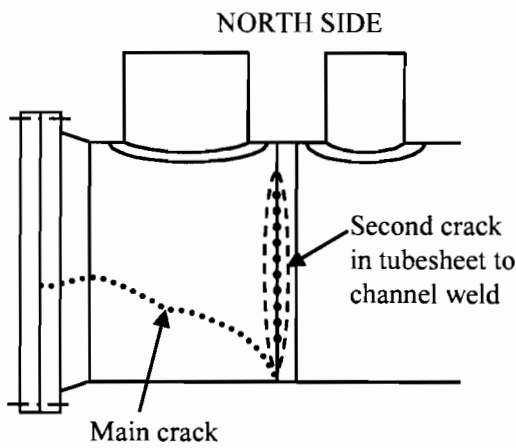
6.17 Figure 6.15 shows a slag inclusion near the root of the weld at the 8 o'clock position. This could have been the initiating point for the possible flaw as seen by the flat area discussed above.



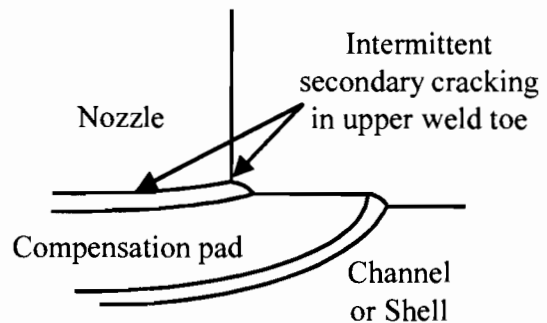
**Figure 6.15 Weld root slag inclusion at 8 o'clock position**

6.18 In addition to the main failure, the event caused other cracks in GP905. These were found in the tubesheet to channel weld between the 2 o'clock and 5 o'clock positions (see Figure 6.16), and in the upper toes of the two east end nozzle compensation pads (see Figure 6.17).

6.19 Both nozzles were found to be inclined away from their original vertical position. The damage to the nozzles and the surrounding plate occurred when the GP905 was lifted off its supporting pillars by the force of the gas and liquid escaping from the rupture, the nozzles bending against the restraining force of the attached pipework.



**Figure 6.16** Second crack in tubesheet to channel weld



**Figure 6.17** Location of the secondary cracks in the compensation pads

6.20 It was confirmed by chemical analysis that the metal from which GP905’s channel plate and tubesheet were made was low carbon killed steel with nominal compositions in line with the metal grade specified for construction. The tensile tests showed that the tensile and yield strengths of the metal were just less than the original test values at the time of construction, but the difference was not of importance with regard to the mode of failure.

6.21 Residual stress measurements were made to help assess if stresses naturally occurring in the vessel could have contributed to the failure. These measurements indicated that there were residual compressive stresses in the tubesheet to channel weld, and their magnitude was less on the inner surface than the outer surface. From these measurements it was concluded that the residual stresses were only a minor contributor to the total stress required for failure, but that they made the inner surface more critical than the outer.

6.22 The toughness tests were undertaken at a range of temperatures to determine “toughness values” for the material for use in the failure analysis. The results showed that the metal

(both the channel plate and the weld) behaved in a pure brittle fashion at -50°C: the fracture surface was smooth, there were no indications of plastic deformation, and the “load deflection” curve was essentially linear. Upon testing, at -30°C, although giving predominantly brittle results, the metal started to show limited plastic behaviour. The fracture surface showed features (ridges). There was some thinning at the failure and the “load deflection” curve showed limited elastic behaviour. As the test temperatures increased, the fractured test specimens showed increased plastic failure characteristics. However, even at 0°C there was still some brittleness.

6.23 By comparing the fracture surface revealed on 25 September 1998 with that of the test specimens, the following conclusions can be drawn:

- For the tubesheet to channel weld fracture, the features on the 25 September surface are like the -30°C and 0°C test fracture surfaces. The metal was essentially brittle, but showed some features (ligaments) indicating localised ductile behaviour. This indicates that the temperature of the weld was in the region of these temperatures and was definitely warmer than -50°C at the time of failure on 25 September.
- For the channel plate fracture (from the 6 o'clock location), the flatness on the inside of the surface which appeared on 25 September is similar to the -50°C test fracture surface. The ridges on the outer surface are more like the -30°C test fracture surface. This indicates that the temperature in the channel was likely to be in this range at the time of failure on 25 September, and that the outer surface was warmer than the inner surface.
- The tubesheet to channel weld was warmer than the channel plate at the time of failure on 25 September.

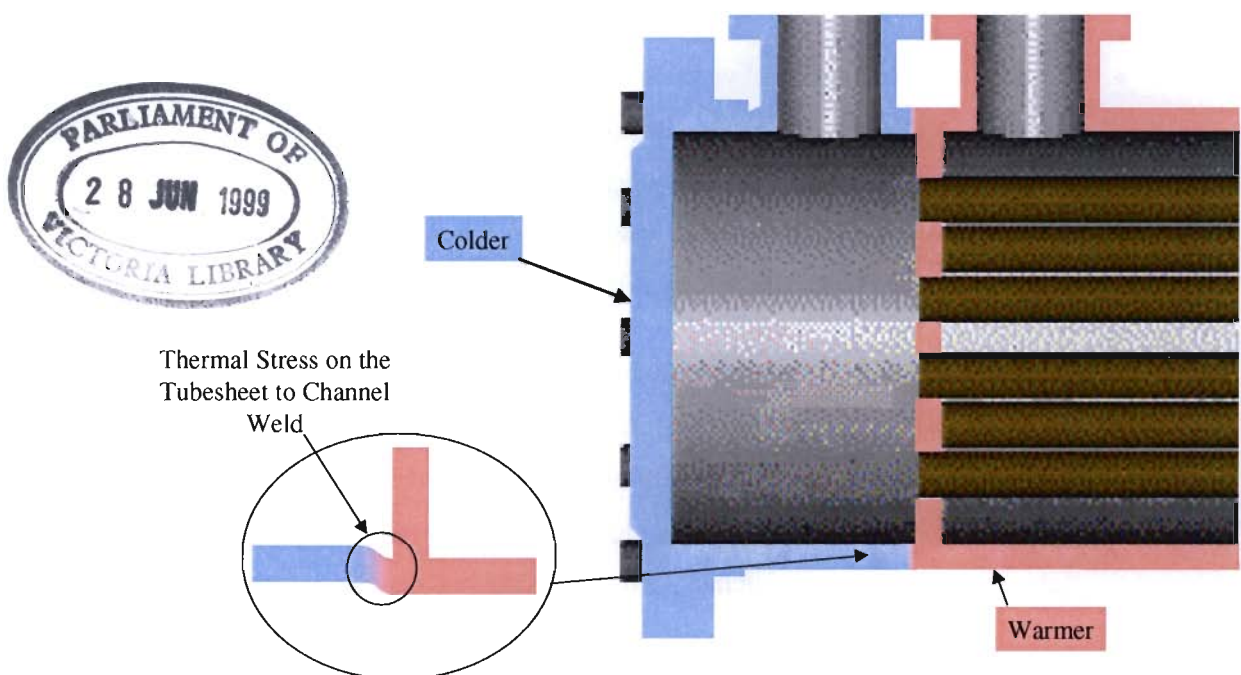
6.24 Cumming's evidence was that he heard “a long rumbling sound like a thunderstorm in the distance” followed by “another louder rumbling noise a couple of seconds later”. This supports the proposition that the failure was slow while in the weld, resulting in the initial noise, and was fast in the channel giving the second louder rumbling noise.

### ***FAILURE ANALYSIS***

6.25 With the defects of the size found at the 8 o'clock position, GP905 would not have failed if its internal pressure was the same as that of the ROD and the metal temperatures were at -48°C. From this it was concluded that another source of stress was required. There was no evidence of any external impact. For this reason, there must have been thermally induced

stresses. A temperature difference of the order of 20°C would have been sufficient to result in the failure on 25 September 1998.

6.26 The modelling method used was finite element analysis. The model calculated the stress in the tubesheet to channel weld due to the stresses induced by the internal pressure and a temperature differential between the channel and the shell. The residual stresses were ignored, as they were small in comparison. The model accepted the shell side being uniformly warmer than the channel of the reboiler, as shown in Figure 6.18. The temperature difference would cause the shell side to expand to a larger diameter than the channel, resulting in stress in the tubesheet to channel weld.



*Figure 6.18 Finite element model for GP905 thermal stress calculations*

6.27 The model calculated the axial stresses for the internal pressure and the 1°C temperature difference in the tubesheet to channel weld. The initial model was enhanced to a 3D model that evaluated the effects of the nozzles on the stress. The nozzles were found to have little effect on the stresses in the tubesheet to channel weld.

6.28 Having determined the stress to temperature relationship, the next step taken was to assess the temperature difference required for an initiating flaw to result in the failure of the vessel.

6.29 The cases modelled were based on the possible flaws identified by the investigation of the failure surface at the 8 o'clock position. The set of cases developed for the modelling of stress were:

### 3D Modelling Cases

- A flaw the size of the flat region found at the 8 o'clock position (ignoring the weld root cavity). This was modelled as a semi-elliptical flaw 18 mm long by 7 mm deep, using a 3D model.
- A combination of a flaw the size of the flat region and the weld root cavity. This was modelled as a semi-elliptical flaw 120 mm long by 7 mm deep. The weld cavity was 230 mm long, so this flaw was conservative in length.
- A combination of a flaw the size of the flat region and the weld root cavity. This was modelled as a semi-elliptical flaw 180 mm long by 7 mm deep. The weld cavity was 230 mm long so this flaw was a better, but still conservative, estimate of the length.
- A small flaw at the weld root cavity. This was modelled as a semi-elliptical flaw 70 mm long by 3 mm and by 4 mm deep (2 cases). The weld cavity was 230 mm long, so this flaw was a better, but still conservative, estimate of the length.

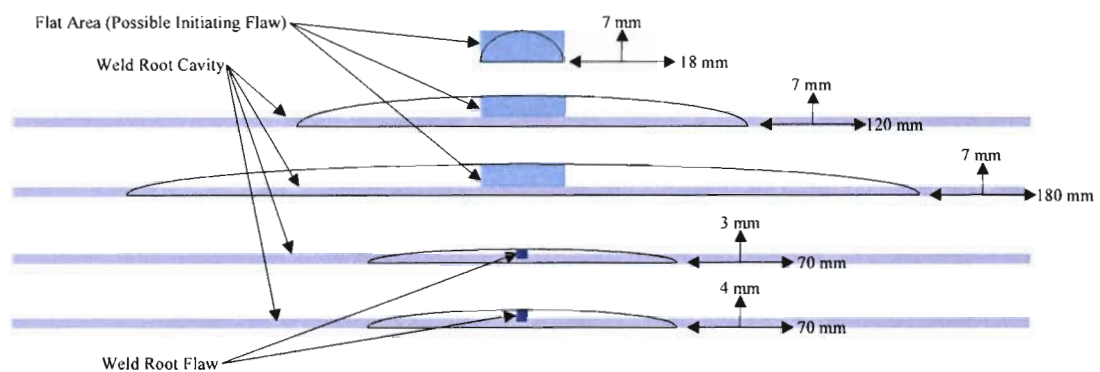


Figure 6.19 Flaw cases for 3D modelling

### 2D Modelling Cases

- Long rectangular flaws of depths 2 mm, 4 mm, 6 mm, 7 mm and 8 mm. The depths were chosen to represent the range of depths of potential flaw from that to the weld root cavity to the flat area.
- 6.30 For each of these cases, the stress intensity factor was calculated and was compared to the fracture toughness values obtained from the tests. This comparison enabled cases that could result in failure to be identified.
- 6.31 The results of the failure analysis found the following:



- At -48°C the vessel would not have failed due to the internal pressure alone for the flaw sizes modelled. (-48°C is the temperature predicted by the process simulation.)
  - For the temperature difference indicated by the investigation of the failure surfaces (i.e. about 20°C) the following initiating flaws could have resulted in failure:
    - A combination of a flaw the size of the flat region and the weld root cavity.
    - A long shallow flaw of the order of 3 mm depth. Flaws of this type were found at the non-failed end, but it was not possible to identify if such a flaw pre-existed at the 8 o'clock position in the failed end due. This was due to the condition of the surface after the event.
- 6.32 Also larger flaw sizes with smaller temperature differences or smaller flaw sizes with larger temperature differences could have resulted in the reboiler's failure if it was at the cold temperatures indicated by the characteristics of the failure surface.
- 6.33 It should be noted that at normal operating temperatures (including start-up and shutdown temperatures), ambient and greater, the fracture toughness of the metal would be such that the flaw sizes and temperature differences modelled would not have resulted in the reboiler's failure.
- 6.34 Given the requirement for heating of the shell side of GP905 for failure, calculations were undertaken to assist in determining the magnitude of the hot lean oil flow into the shell side of the reboiler to result in a 20°C temperature difference across the tubesheet to channel weld. These calculations were aimed at ascertaining generally the magnitude of flow required, rather than accurately modelling a specific scenario. This was because the affect of the evidence concerning the restarting of the GP1201 pumps was unclear.
- 6.35 An axisymmetric model of the heat transfer process and the resulting stress distribution was prepared using Strand 7 Finite Element Method software. This model calculated the temperature in the tubesheet to channel weld for different conditions in the shell and tube (channel) sides of the reboiler.
- 6.36 In developing the cases to be modelled, consideration was given to the possible conditions in GP905 before the attempts to restart lean oil flow on 25 September 1998. The process simulation had calculated the temperature in GP905 as -48°C and, given the ongoing flow of cold condensate via the FRC7 valve, the tube side of GP905 would have been full of liquid.

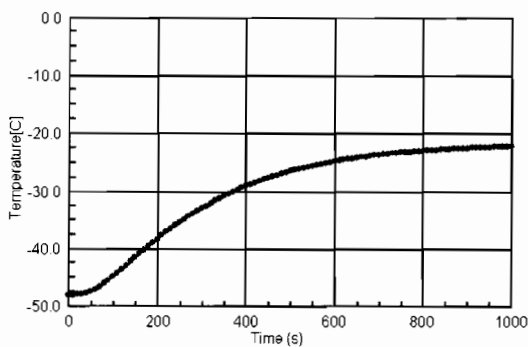
6.37 The flow of hot lean oil into the shell side would have evaporated the tube side liquid unless there was a flow of liquid down the ROD that replaced the evaporated vapour. Assuming no liquid make-up from the ROD, a simple heat balance calculation indicates a lean oil flow of 1000 l/min and 200°C would have boiled away the condensate in the tube side of GP905 in about three and a half minutes. The 1000 l/min of lean oil flow is the set point for LFSD8. It is therefore the minimum flow through the GP1201 pumps. 200°C is a representative value for the temperature of the lean oil on reaching GP905, based on PIDAS and chart readings. In reality, the heat from the lean oil on the shell side would have produced localised vaporisation from the upper tubes. Vapour leaving each end of these tubes would have impaired proper circulation and decreased heat transfer. Hence the time required to boil the tube side dry would have been longer than the three and a half minutes calculated, which should be considered a minimum.

6.38 Two cases were modelled to give estimated times to failure, given a continuing lean oil flow:

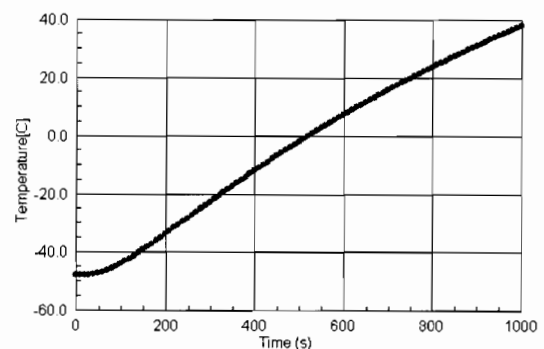
Case 1 - Channel being full of liquid.

Case 2 - Channel being full of vapour (i.e. empty of liquid).

6.39 Figure 6.20 and Figure 6.21 show the results for the two cases modelled. From the graphs it can be seen that the time taken for the temperature of the tubesheet to channel weld to increase to 20°C greater than the channel is of the order of three and a half to seven minutes.



**Figure 6.20 Temperature at tubesheet to channel weld for Case 1**



**Figure 6.21 Temperature at tubesheet to channel weld for Case 2**

6.40 The evidence indicates that there were two attempts to restart a GP1201 pump and that the flow would have been through (not around) GP905. It is not possible to state with certainty when the restart attempts took place, but based on the radio transcript, they were about 13 minutes and 9 minutes respectively before the time of the rupture. Also the evidence is

that a GP1201 pump started on both occasions, but it is unclear if there was flow and if there was, how long it lasted. The GP1201 pump certainly stopped after the first attempted restart.

- 6.41 Given the requirement for a temperature differential and based on the times specified above, it follows that the starting of the GP1201 pumps resulted in lean oil flow.

***METALLURGICAL INSPECTIONS, TESTS AND FAILURE ANALYSIS***  
***CONCLUSIONS***

- 6.42 GP905 failed catastrophically due to brittle fracture with localised ligament failure. The internal pressure alone was not sufficient to cause the failure of the reboiler, hence an additional source of stress was required. On the balance of probabilities, the additional stress required to cause the failure arose from the temperature differences between the channel and shell. The higher temperature in the shell was due to the introduction of hot lean oil resulting from the restart attempts of the GP1201 pumps.

# Chapter 7

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## **THE FIRE, THE EXPLOSIONS AND THE RESPONSE TO THE EMERGENCY**

### ***THE INITIAL VAPOUR CLOUD AND ITS IGNITION***

- 7.1 From an engineering assessment made of the volumes and mass of the various flammable hydrocarbons that were contained within GP1 at the time GP905 ruptured, it appears that somewhere between 20,000 and 25,000 kilograms (20-25 tonnes) of sales gas, ethane, condensate, and lean and rich oil were liable to escape from the rupture of GP905.
- 7.2 Various witnesses described a thick white vapour cloud or fog forming in the vicinity of the ROD/ROF area. The cloud almost immediately began to drift in a south to south-easterly direction. The contents of the ROD were at a pressure of 2800kPa and provided the force for the initial release. This pressure, when released, was sufficient to blow off their feet those attending to the leak from the adjacent exchanger GP922. Further, the force of this initial jet of gas and liquids dug a hole in the ground directly below GP905, which was later measured to be approximately 1.5 metres in diameter and 1 metre deep. The gravel and dirt from the hole was sprayed around by the gas jet, denting the light aluminium cladding covering some of the adjacent vessels.
- 7.3 The south-south easterly drift of the vapour cloud from the ROD/ROF area was towards the general direction of the gas-fired heaters, located approximately 170 metres away at the southern boundary of the plant. It would have taken in the order of 30-60 seconds for the cloud to drift this distance. During this time, upwards of 10,000 kilograms (10 tonnes) of flammable hydrocarbon gases, vapours and liquids were released from the ruptured reboiler GP905.
- 7.4 The development of the cloud was modelled using a computer simulation code. This modelling demonstrated that the front edge of the cloud would have contained a sufficient mixture of flammable hydrocarbons and air for it to ignite once it found a suitable ignition source. The burn pattern of the cloud, the eyewitness descriptions of the movement of the flame front and the lack of any significant overpressure damage, all support the conclusion that the front edge of the cloud ignited once it reached the fired heaters. It is probable that the cloud was ignited by the hot oil heater AX501 or the regeneration gas heaters AX502A and AX502B, all of which were still being fired.

- 7.5 The main area between the ROD/ROF section of the plant and the heaters into which the cloud had dispersed was very open. Having ignited at its front edge, a flame front developed and then burnt back through the vapour cloud, along the north/south piperack to the source of the release, namely GP905. When it reached the exchanger the cloud erupted into an ‘angry red orange ball of fire’. While the term ‘explosion’ has been used to characterise the ignition of the initial vapour cloud, the appropriate technical term to describe this ignition is a ‘flash fire’ or ‘deflagration’. However, it is convenient to use the term “explosion”, particularly as that term is used by the Terms of Reference.
- 7.6 Once the flame front of the vapour cloud reached the GP905 exchanger, it would have ignited the continuing jet of gases and liquids escaping from the rupture site. As the initial release consumed upwards of 10 tonnes of hydrocarbon materials, this meant another 10-15 tonnes of materials were still contained within GP1. All of this material was available to fuel the continuing fire emanating from GP905 and GP922 for a matter of hours and gave rise to flames as high as three-quarters the height of the ROD. The flames emanating from GP905 and GP922 impinged on the overhead piping in the east-west piperack. As the metal walls of these pipes were heated to their failure temperatures, they began to rupture. The smaller pipes first began to rupture in a matter of minutes, as described by Cumming, with the larger pipes rupturing later as recorded on the security videos.

### ***THE EMERGENCY RESPONSE PLAN***

- 7.7 Under s.14 of the *Country Fire Authority Act, 1958 (Vic)*, the control of the prevention and suppression of fires in the country area of Victoria is vested in the Country Fire Authority (CFA). Longford is within the country area of Victoria. Section 20AA (2) (a) of the Act gives the CFA power to enter into agreements or arrangements for the provision of its services. The CFA entered into such an agreement with Esso and on 25 September 1998, the relationship between Esso and the CFA was governed by that agreement. It was known as the Joint Emergency Management Agreement. Under this agreement, Esso had a duty to report immediately to the CFA regional headquarters at Sale all fires and emergencies. It was agreed that, based on the information contained in the initial report, the CFA would activate the appropriate level of fire brigade response.
- 7.8 The agreement provided that upon arrival at the fire or emergency, the CFA officer in charge was to consult with the Esso emergency co-ordinator and would then assume the responsibility of incident controller at an appropriate location. The incident controller, in full consultation with the Esso leader of operational response, would establish an appropriate joint Esso/CFA Incident Management Team (IMT) and the IMT would maintain

liaison with senior Esso managers throughout the emergency. The incident controller was to develop emergency objectives and strategies in consultation with the IMT. However, the Esso leader of operational response would retain the command of Esso personnel present at the emergency and would, to the extent practicable, act in accordance with the instructions of the incident controller.

- 7.9 Esso had three manuals dealing with response to an emergency. The first was the Emergency Preparedness System Manual, which dealt with the management system in the event of an emergency. The second was the Emergency Response Manual, which contained information needed if an accident occurred. The third was the Emergency Response Support Data Manual, which contained detailed emergency instructions and support material. The Emergency Response Manual required the person in charge at the site of an emergency to determine whether the emergency was level S – one that could be brought under control with personnel and equipment at the site, - or level O - one that required outside assistance. For level O emergencies, a category within which the accident at Longford on 25 September 1998 clearly fell, the leader of the Crisis Management Team (CMT) was to be responsible for the accident management with the advice of the leader of operational response.
- 7.10 The CMT was situated in Esso House in Melbourne and was comprised of persons possessing the training or skills necessary to deal with all aspects of an emergency. The leader of the CMT on 25 September 1998 was Peter Coleman. The Emergency Response Manual also envisaged forward controllers and field teams, presumably at the site of the emergency, as part of the accident response. However, the manual observed that “the extent to which we would use this structure in practice depends on the nature of the particular emergency that may arise”.
- 7.11 In fact, no classification of the emergency at Longford was made nor was there any practical need for such a classification. Peter Wilson, who was the person in charge at the site, was killed and Peter Hiskins, a construction supervisor, assumed the role of leader of operational response. However, it appears that senior sergeant butler, who was stationed at the Sale Police Station, rang the plant manager’s secretary, Angela Jones, after learning of the emergency and asked whether it was big enough to initiate DISPLAN. DISPLAN was the original State disaster plan which had been replaced by the Emergency Management Manual Victoria and no doubt, Senior Sergeant Butler was intending to refer to the latter. Jones replied that the emergency was big enough, but it is clear that the *modus operandi* adopted at Longford on 25 September 1998 was that contained in the agreement between Esso and the CFA. Nevertheless, under the manual, Senior Sergeant Butler was the designated

emergency services co-ordinator. He was present at Longford during the emergency and carried out his duties in that capacity.

### ***THE EVENTS WHICH OCCURRED FOLLOWING THE ACCIDENT***

- 7.12 Although the agreement between Esso and the CFA required Esso to report explosions and fires to the CFA regional headquarters at Sale, the CFA learned of the accident from the police rather than Esso. Angela Jones was in her office in the administration building at Longford when the first explosion occurred and rang security at the main entrance guardhouse to find out what had happened. She then heard the second explosion and rang the Sale police station where her husband, a policeman, was stationed. Jones spoke to another police officer and told the officer that there had been an explosion and that ambulance, fire brigade and police coverage was needed. The police at Sale, upon receiving Jones' telephone call, notified the D24 communications centre in Morwell of the accident. The operator there in turn notified the Morewell Urban Fire Brigade, which in turn notified the Sale Urban Fire Brigade (the Sale Brigade) and the Longford Urban Fire Brigade (the Longford Brigade) at 12.43 pm.



*Figure 7.1 The first film of the fire, taken at 12:41:55*

- 7.13 Around this time (12:41 according to the video time stamp), the guards in the main entrance guard house repositioned two of their security video cameras so as to video tape the fire. The first video recorded picture of the fire (Figure 7.1) shows a red yellow flame with a height of between 15 and 20 meters and a thick cloud of black smoke drifting in a south-easterly direction. The relevant time stamp on this figure and subsequent figures depicting photographs from the security video camera, is the one appearing at the very top of the figure.
- 7.14 Jones went to the Emergency Response Procedure (ERP) room which was also located in the administration building. Under Esso's emergency procedures, it was Peter Wilson's responsibility to run the ERP room but Jones knew that there were no management personnel about, so she undertook the task. She rang Peter Hiskins, who had just left for Sale, and informed him of the situation at the Plant.
- 7.15 Upon returning to Longford a short time later, Hiskins went straight to the ERP room expecting to see Peter Wilson in charge. He tried to contact Wilson by radio, but there was no response. Hiskins then took charge of the situation as the Leader of the Operational Response Team in accordance with Esso's emergency procedures. He organised a headcount and confirmed that the ESD for GP1 had been activated. He ordered all non-essential personnel to evacuate the plant. Shortly after this, Peter Coleman rang Hiskins from the CMT Centre in Melbourne. Coleman ordered the ERP room to be moved from the administration building to the heliport across the road. Hiskins carried out the order and then went to the canteen where injured personnel had been located, to arrange for such persons to be removed. Hiskins' main concern at this time was to ensure that the deluge system on the LPG accumulators was working. The system appeared to be working, but it was not until later in the afternoon that an aerial inspection confirmed this to be so.
- 7.16 Upon the activation of ESD1, GP2 and GP3 switched to recycle mode. This kept those plants operating but not producing sales gas. At about 12.45 pm, the GP2 and GP3 control room operators, David Delahunty and Kurt Mielke, were instructed to evacuate the plant. Before doing so they initiated a full shutdown of GP2 and GP3.
- 7.17 Robert Langridge, a CFA operations officer, was in charge of Region 10 headquarters in Sale. He first became aware of the accident at Longford at about 12.45 pm when a local television station telephoned him to query what was going on. He was in the process of contacting the police to clarify the situation when he heard on the CFA radio that the pagers carried by volunteer firefighters in the Sale Brigade had been activated and that the Longford Brigade had responded to an accident at the Longford plant. He then received a



telephone call from the Morwell Urban Fire Brigade to say that it had just deployed the Sale and Longford Brigades. At about the same time he heard the Sale fire siren operating.

7.18 Langridge and Mark Jones, another CFA operations officer who was present at Region 10 headquarters at the time, then drove to the Longford plant which was about 18 kilometres away. They arrived at 1.07 pm, ahead of the Sale and Longford Brigade tankers.

7.19 At 1.00 pm, only minutes before their arrival, the security video cameras recorded a major explosion from the site of the fires. A ball of flames approximately 40m in width and at least 70m high erupted from ROD/ROF area. This explosion was a consequence of the rupture of one of the large pipes in the east/west piperack in the King's Cross area and the subsequent release of its contents to the atmosphere in the immediate vicinity of the seat of the fire.



*Figure 7.2 The first major release, at 13:00:40*



*Figure 7.3 The first major release, at 13:00:43*



*Figure 7.4 The first major release, at 13:00:46*



- 7.20 At about 1.00 pm the Royal Australian Air Force (RAAF), which has an air base near Longford at East Sale, and which has its own firefighting equipment and personnel, learned of the explosion and fires. At about 1.10 pm the RAAF dispatched a Trident fire tender, which is similar to a pumper, and three fire crew to the Longford plant. These were placed on standby by the CFA. A further fire tender and a crew of three were dispatched to Longford by the RAAF. The RAAF also supplied additional support facilities in the form of a transport vehicle with a HAZMAT trailer containing equipment for fighting fires involving hazardous materials and a crew of three. It also supplied maintenance fitters, communications equipment, breathing apparatus, foam and bushfire pumps with a crew of two. A RAAF relief crew was made available for the duration of the emergency.
- 7.21 Upon their arrival at Longford, Langridge and Jones observed a significant number of Esso personnel, distinctive in their orange overalls, outside the plant on Garretts Road. From the guard house Jones saw a fire with flames approximately three-quarters of the height of the ROD tower in the vicinity of GP922 and GP905. There was thick black smoke drifting off in a westerly direction.
- 7.22 Also upon arriving, Langridge assumed the role of incident controller and Mark Jones assumed the role of Operations Officer. These roles are prescribed by the Australian Inter Service Management System as part of the IMT. That system has been adopted by the CFA. Two further CFA staff officers, Simon Bloink and Brian Smith, were included in the IMT as Planning Officer and Logistics Officer respectively.
- 7.23 In the meantime, at 12.57 pm two members of the Sale Brigade left for Longford from the Sale Fire Station in a CFA patrol vehicle. They were Murray Quine, who was the Captain of the Sale Brigade, and Doug Brack, a volunteer member of the CFA and also an Esso employee. The Sale pumper, which pumps water drawn at the site, was to follow. The Sale tanker, which carries its own water, and other CFA firefighters were also to follow. Brack and Quine arrived at the Longford guardhouse at 1.15 pm and met with Senior Sergeant Butler.
- 7.24 Security personnel on contract from Chubb Security Australia Pty Ltd were present in the guardhouse when Brack and Quine arrived. So too were some Esso employees, but there were no Esso management personnel present. By this time, the Sale Brigade pumper and tanker, having arrived at the radio tower about one kilometre from the plant, were awaiting instructions.

- 7.25 At 1.19 pm a decision was made to allow CFA personnel and the Sale Brigade pumper into the plant, but the Chubb security staff were reluctant to let them through the entrance gate. The problem appears to have been that the security personnel regarded themselves as bound by the plant entry procedures which required all persons entering the plant to be registered. This meant that CFA fire fighters had to get out of their vehicle and register their personal details before they were let in. After a protracted discussion between the CFA and the security staff, it was agreed that the CFA would provide the numbers of the CFA personnel entering the plant but that individuals would not be required to provide their personal details. Another entry procedure, which required non-Esso personnel to be accompanied by an Esso employee, was overcome when Quine sent Brack, an Esso employee as well as a volunteer fire fighter, to escort the pumper into the plant. Nevertheless, the difficulty with the security staff caused a 10 minute delay in the entry of the first firefighting unit to the plant.
- 7.26 When the problem with the security staff was resolved, Langridge, in consultation with Jones, decided that the CFA should not engage in firefighting activities for the time being, but should use water streams to cool the plant and equipment in the vicinity of the fire until the substances feeding it were exhausted. There was also the problem of the explosions. Jones set up a control point at the guardhouse and contacted units on their way to Longford to advise them of the situation. He realised that radio and mobile telephone communications were a problem because of the geographical features at Longford and he arranged for a mobile communications van to come from Bairnsdale. Until the van arrived, communications took place through the CFA's Stradbroke sub-base, which monitors all radio traffic for the Stradbroke group of fire brigades.
- 7.27 Langridge and Senior Sergeant Butler proceeded to the fire shed in the vicinity of the ROD/ROF area of GP1 to assess the situation. At this time, which was about 1.20 pm, there was a large fire in the piperack adjacent to the ROD, generating flames of between 20 and 30 metres in height and large volumes of black smoke. Three or four monitors were spraying water on to the fire and two Esso personnel were present. The Esso Austral teleboom, which had a remotely elevated monitor on a telescopic boom, was being used to spray water on to the fire high up on the ROD tower.
- 7.28 Jones arrived at the fire shed shortly afterwards. It was at this time that there were two small explosions within a minute of each other, the latter being the larger. As a consequence, the intensity of the fire increased. Visser came up to the fire shed and told Langridge that he was in charge of Esso personnel. He said that ground monitors had been put in place and that one or two persons were missing.

7.29 After gaining entry, the Sale pumper was the first fire brigade appliance to reach the fire. It took up position in the vicinity of the GPI control room. At about 1.26 pm, while the Sale Brigade fire crew were positioning hose lines, there was a further explosion at the seat of the fire which dramatically increased its size and intensity. One witness described it as an explosion at the base of the fire and a large fireball erupting into the air. The security cameras recorded this explosion and fireball at 13:22:47.



*Figure 7.5 The second major release, at 13:22:47*

7.30 The CFA drew heavily on its resources in places other than Sale and Longford to respond to the emergency. At an early stage, senior CFA officers ordered hydraulic platforms, fire tenders and tankers, fire pumpers, telebooms, breathing apparatus, a support mobile vehicle, mobile foam tender modules, hose layers and aerial appliances. These were obtained from various places in the State including Bairnsdale, Boronia, Traralgon, Morwell, Ferntree Gully, Scoresby, Geelong, Chelsea, Noble Park and Dandenong. Most of these resources were not used but were kept on standby outside the plant during the emergency.

7.31 Langridge was concerned that the fire might impinge on the LPG accumulators causing a catastrophic boiling liquid expanding vapour explosion (BLEVE). Also, Visser advised that he could not be sure that the plant was stable. Langridge ordered all persons in the vicinity of the fire to withdraw to the fire shed and subsequently to the ERP room, which at this time

had not been evacuated to the heliport and was being used as the Incident Control Centre for the emergency services. The Sale pumper was left in position, playing water from the fire mains system on to the fire. Langridge examined the options for extinguishing the fire with Esso personnel in the ERP room. It was agreed that all fire crews should withdraw and allow the fire to burn itself out. For this to happen it was necessary to shut off all fuel supplies to the ROD/ROF area.

7.32 At about 1.35 pm the final and largest explosion occurred. The explosion was preceded by an evident reduction in the noise level of escaping gas. At the time it occurred, Quine and Brack were at the eastern end of the GP1 combinaire. The force of the blast was sufficient to knock them off balance. The blast was accompanied by intense heat. Quine and Brack observed a large fireball rise into the air and saw the metal ladder on the ROD tower melt rapidly.

7.33 The security cameras recorded this blast as occurring at 13:32 hours. As can be seen from the pictures, the flame heights were in excess of 100 meters high and 55 meters wide.



*Figure 7.6 The third major release, at 13:32:31*



*Figure 7.7 The third major release, at 13:32:34*



*Figure 7.8 The third major release, at 13:32:37*



*Figure 7.9 The third major release, at 13:32:41*



*Figure 7.10 The third major release, at 13:32:43*



- 7.34 At 1.50 pm, Langridge ordered the removal of the Incident Control Centre from the ERP room to the heliport. At 2.08 pm the police were asked to evacuate civilians within a five kilometre radius of the plant and to evacuate all non-essential personnel from the heliport. An air exclusion zone was imposed when a media helicopter arrived at the heliport.
- 7.35 At about 2.00 pm, a meeting was held at the heliport between Esso staff and the CFA. It was confirmed that no attempt should be made to extinguish the fire until all fuel sources had been isolated. Langridge sent Esso personnel into the plant for the purpose of isolating further fuel sources to the fire. CFA personnel accompanied the Esso team and manned fire hoses as a protection measure. Whilst this was being done, the Incident Control Centre was relocated to the Esso fire shed. Monitors were redirected because of the change in wind direction.
- 7.36 The isolation of fuel sources involved shutting valves in and around the ROD/ROF area. This meant walking underneath the piperacks and following the line of the damaged pipes in order to establish the appropriate isolation point. As the piperacks were raised above the ground on concrete pillars, the Esso workers and the firefighters were standing underneath the pipes looking into the fire above. Many of the pipes had become twisted and broken and it was difficult to see where they led and to locate the isolation valves to shut them in. A number of the isolation valves were heat damaged and, even when they were blocked off, gas continued to escape from them. The piperack areas in GP1 were severely damaged, leaving the cement pillars cracked and the steel reinforcing exposed. However, isolations were effected and the severity and height of the fire were reduced.
- 7.37 Peter Burley, an Esso operator, says that he assisted Neale Burton, another Esso operator, to compile a list of the lines in the piperacks to assist in the isolation procedure. He says that they had to do this from memory and their own books because no documentation existed to identify the lines located in the Kings Cross area. In fact, Burton used a hand drawn map that he had prepared in 1992, to identify isolations which were effected.
- 7.38 Consideration was given to the use of further aerial appliances, such as telebooms, for combating the fire. After discussions with two of his officers, Langridge decided that there would be no advantage in deploying aerial appliances, because the monitors in place were sufficient to achieve the cooling required. There was, in addition, concern about the continuation of the water supply and, although no persons or equipment were in a position of danger, a further explosion could not be discounted as Esso personnel were unsure of the fuel sources to the fire.

7.39 At 2.12 pm Robert O’Shea, a plant supervisor, arrived at the plant to relieve Visser. He met with Langridge and Jones. They determined that ground monitors needed to be redirected to operate more efficiently and that the bore pumps needed to be checked.

7.40 By 2.25pm the flames in the vicinity of the GP905 exchanger had diminished. The fire as recorded on the security video camera (at approximately 2.26 pm) consisted of a red-orange flame approximately 10-15m in height and a large plume of thick black smoke.



*Figure 7.11 The fire at 14:26:02*

7.41 At about 3.00 pm, the spray of water from the Esso teleboom needed to be redirected, there having been a change in wind direction, but a hydraulic failure in that piece of equipment made it ineffective. At about the same time, Jones observed that the hose line from the Sale pumper had burst so he shut the pump down.

7.42 David Sherry, the CFA operations manager, arrived at the plant at 3.30 pm. He was then the senior CFA officer on-site. On his arrival he was briefed by Langridge. He endorsed the approach taken, which was to contain and isolate the fire. Sherry agreed that until all fuel sources were isolated, there was a potential for the discharge of vapour and liquid to cause an increase in the fire or further explosions.

- 7.43 By this time the flames in the fire area had died down to below 10 metres in height accompanied by a large billowing cloud of black smoke.



*Figure 7.12 The fire at 15:26:02*

- 7.44 Langridge spoke with Hiskins at the heliport and at 3.57 pm ordered an aerial inspection of the scene of the accident by Esso helicopter, not only to make a complete assessment, but also to ensure that the LPG accumulators' deluge system was working efficiently. Quine, Jones and Peter Ronalds, an Esso employee, conducted the aerial inspection. They ascertained that the LPG deluge systems were working and that the flare system was operating normally, which meant that there were no significant pressure changes in the plant that might have led to a further explosion.
- 7.45 Sherry considered that Langridge was handling the situation appropriately and should remain as incident controller on-site. Sherry regarded his own function as being to provide assistance if required. He conferred with the police on the site and, after familiarising himself with the details of the accident, briefed the media who were present. He remained on site until 2.00 am the next morning, 26 September, before returning at 7.00 am to take over the role of incident controller.
- 7.46 The plant manager, Will Harrison, had been at Long Island Point on 25 September giving a lecture on safety. When informed of the accident at Longford, he returned there

immediately. On his return at about 3.30 pm, Harrison assumed the role of emergency co-ordinator, carrying out his duties from the heliport.

7.47 When Coleman arrived at Longford, Harrison was already there. After receiving a briefing from him, the technical team accompanying Coleman was instructed to devise plans for isolating GP1 from the CSP, GP2 and GP3 and to ensure that all remaining hydrocarbon inventory was safely isolated.

7.48 At 4.27 pm there was a report to the Incident Control Centre that there were small fires around the LPG booster pumps and the product debutaniser. It was also reported that there were small fires on the flanges on the east side of the product debutaniser. The isolation of the absorbers cut fuel supplies to the debutaniser and the fires were extinguished. The security videos shows that at this time the top of the flames were just visible from the entrance gate, over the roof of the building in the foreground. The smoke had also lightened.



*Figure 7.13 The fire at 16:26:02*

7.49 At about 5.00 pm on 25 September, Jones had become concerned about the supply of water in the water storage tanks. These were the tanks that were supplied from three groundwater bores. The water supply from the tanks represented a single system for the plant, using the fire mains for distribution. At about 5.15 pm Chris Lyon, a CFA Lieutenant and an Esso

employee, was directed to check the level of water in the water storage tanks. He found that the gauge for one tank showed zero and the gauge for another showed a level which was only 18% of its capacity. The electric pumps from the groundwater bores were not working. It was then realised that when the ESD was activated it had shut down everything, including the generators. It is possible that the damage to the GPI switch room may have caused the electric pumps not to operate. In any event, Esso personnel managed to get two of the three backup diesel pumps working within a short time, but the third diesel pump had been taken out of service on the previous day for maintenance. This resulted in a reduced capacity to fill the water storage tanks. The situation was reported to the Incident Control Centre and arrangements were made for boosting water into the fire mains from the south pond. There was no means provided to draw water from the pond so a means had to be devised. It was decided to run a suction hose from the pond to a pumper to pump water from the pond into the fire mains through the risers or hydrants which were located at various points along the fire mains ring system. The water could then be withdrawn from the fire mains using fire hoses. When this was attempted it was found that the fittings on the risers were not compatible with the fittings on the CFA pumpers and it was necessary to use adapters.

7.50 Lyon recalled that Esso had previously advised the CFA that adapters were located in the back of the Esso fire shed. Together with others, Lyon went to the fire shed but could not find the adapters. Eventually Quine, Brack and Colin Skeen, a Lieutenant with the Sale Brigade, broke into two or three cupboards in the fire shed with bolt cutters and located two adapters. The pumper from Chelsea commenced drawing water from the pond. It was then pumped to the Ferntree Gully and Traralgon pumpers to increase the pressure. With the additional pressure, the water was pumped into the fire mains ring. By this means, the CFA established a water relay from the pond which ensured that the volume and pressure remained constant. The water from the pond was sufficient to allow the two operating diesel pumps to replenish the water storage tanks from the bores during the night.

7.51 The problems with low levels in the water storage tanks and in locating the adapters delayed firefighting operations for about an hour. It was necessary to withdraw Esso and CFA personnel from the area of the fire and to reduce the number of water lines to the fire. It was not until 7.15 pm that the water relay was successfully established so that firefighting crews could move back into the plant to contain the fire and further attempts could be made to isolate fuel sources.

7.52 The control objectives of the IMT were set out in a situation report prepared at 5.30 pm on 25 September. They were to continue cooling the fire area, to isolate all possible feeds to the impact zone, taking care of possible pressurisation due to isolation, to apply water by the

use of aerial appliances from behind the ROD to the pipework at the rear of the control room, to set up foam teams in case fires started in the drains, to maintain a pumper relay team on standby and, in the event that there were water supply problems, to cut back on the water used in the deluge system for the LPG accumulators. That system was working well, but was using a lot of water. At this time it was observed that it was likely that the fire was being fuelled by liquid hydrocarbons rather than gas, which was more favourable from a safety point of view.

- 7.53 By around 5.30 pm the flame height in the vicinity of the seat of the fire had diminished further. The flames were yellow-red in colour and approximately 10-15 metres in height.



*Figure 7.14 The fire at 17:26:02*

- 7.54 At this time members of the fire team were able to move in close to the fires that continued to emanate from the two exchangers GP905 and GP922. The picture depicted in Figure 7.15 was taken by one of the members of the team. The flames from GP905 depicted in the photograph, were approximately three meters in length and one meter wide. The flames from GP922 were fan shaped, emanating from various gaps between the end plate and the exchanger body.



*Figure 7.15 The fire from behind the GP1201 pumps, at approximately 5.30 pm*

7.55 At 5.45 pm on 25 September there was a meeting between Esso management and the CFA. Harrison raised the question of the rescue of Wilson and Lowery. Langridge agreed that Harrison should organise two Esso rescue teams with full safety clothing. Steve Bennett and Peter McFarlane were to be one team and Ray Huddy and Brian Holt the other. A CFA officer was to lead each team. Whilst the teams were within 50 metres of the fire preparing for entry, a direction was given by a representative of the Coroner that, if the missing men were found dead, the bodies were to be left where they were. At 5.55 pm, Langridge postponed the use of the rescue teams for safety reasons and by 6.05 pm their use was cancelled. Langridge indicated that the CFA would conduct a search as soon as possible.

7.56 At 7.13 pm, Brack from the CFA located the body of Lowery, although it could not be identified until the following day. The body was against a concrete pillar on the south-east corner of Kings Cross approximately 10 metres from the eastern end of GP922. Arrangements were made to cover the body with blankets. Dr Ian Nicholson, a clinical forensic physician for the Victoria Police and a general practitioner at the Sale Hospital, examined the body to confirm death. It was decided that it was unsafe to remove the body and it was left where it was pending safe access.

7.57 At 10.00 pm on 25 September there was a major changeover of personnel at the plant. CFA regional officer Euan Ferguson took over from Langridge as incident controller. Graeme Lay took over from Mark Jones as IMT operations officer. At this time there were about 12 fires still burning from pipes of various sizes, but they were contained. The strategy adopted was to continue trying to contain the fires, to cool and protect the exposed plant and equipment and put out the fire by isolating the fuel sources

### ***26 SEPTEMBER (SATURDAY)***

7.58 At 1.00 am on Saturday, 26 September, there were two teams of Esso operators, ten persons in all, working on the isolation of valves close to the fire. The isolations were carried out on the basis of the operators' knowledge, by following lines where practicable, by reference to the P&IDs and at the direction of the supervisor. The planning of the isolations was apparently done under the supervision of Hiskins and O'Shea on a whiteboard in the ERP room. No record was kept of any plan and this would confirm that the isolations were carried out in an ad hoc manner.

7.59 The staging area was relocated to the Longford community hall and two telephone lines were installed to provide adequate communications. Otherwise matters remained steady throughout the night. The CFA continued to maintain a cooling screen of water by using five to seven monitors directed at the fire. The deluge system was running constantly on the LPG accumulators.

7.60 The CFA strategy remained the same, namely, to continue with the isolation of valves under the protection of fog, that is, water from fire hoses. The area covered by the 12 or so fires was approximately 20 square metres with flames varying in length from ten centimetres to four metres coming from split and ruptured pipes in the ROD/ROF area.

7.61 At 7.00 am on Saturday, 26 September, Sherry returned to the plant and relieved Ferguson as incident controller. Arthur Haynes, a CFA operations officer, relieved Lay as IMT operations officer. Allan Smith became deputy operations officer. At this time the fires were still burning, but with decreased intensity. By 6.30 am it was realised that, whilst the fires would continue to burn out slowly, the process of effecting isolation of inventories feeding the fires was going to take much longer than at first anticipated.

7.62 At 6.55 am on Saturday, 26 September, Peter Wilson's body was located. Graham Lay, an operations officer with the CFA, discovered it directly under the pipework north of the eastern end of GP922 and about five metres north east of where Lowery's body was found.



Because of the fire in the piperack above the body, it was not possible to cover it and it was left where it was pending safe access.

- 7.63 At 9.00 am the CFA Structural Operations Performance Evaluation Report team and other CFA personnel met and were briefed by CFA deputy chief Bill McIntosh. The established objectives were to extinguish the fires, cool exposures, stabilise the site and maintain protection before restarting GP2 and GP3, but the CFA reviewed its strategies from time to time. The main concern was the ongoing uncertainty that existed about the isolation of inventories feeding the fire. Some gas from unidentified sources was still escaping, but the IMT was satisfied that it was being dispersed through the continued application of water.
- 7.64 Geoff Evans, a CFA operations manager, was concerned about the ad hoc nature of the isolation of fuel sources. At 2.30 pm on Saturday, 26 September, he had a discussion with Mick Brack, an Esso acting operations superintendent. He asked Brack for a detailed plan of the plant's pipework to assist the IMT in identifying which valves should be isolated to stop the flow of fuel to the fires. Brack said that he did not have a plan available and that in any event, the Longford plant was a hybrid, having had its original design modified on a number of occasions, so that a plan, even if one could be located, might not have been of much assistance.
- 7.65 By 3.00 pm, only a small flame was emanating from the GP905 heat exchanger itself and there were fires at three locations in the piperack near the Kings Cross area.
- 7.66 At 3.30 pm on 26 September, an IMT meeting with Esso representatives was held. The meeting was addressed by Visser, who said that Esso had isolated as many lines as they could but the flare line could not be isolated because it was still burning from the CSP. He said that one or two gas lines were split and burning. Other lines were being purged with water, but it was obvious that there were further gas lines that needed isolating even though it could not be ascertained exactly where the fuel was coming from. Visser's view was that, even though the de-ethaniser line was closed at both ends and was soon to be flushed, there was a possibility that the burning off of fuel could take days. The IMT strategy at this time was to let the bottom lines to the ROD burn out however long it took.



*Figure 7.16 Photograph taken at approximately 14:45 pm, 26 September, showing seats of fire in Kings Cross piperack*

7.67 The IMT continued to review its strategy. At 4.00 pm on 26 September, it confirmed its policy of containment and isolation. Esso personnel were continuing to identify pipes in an effort to isolate individual fires and stabilise the situation before restarting GP2 and GP3. The policy was confirmed at 5.00 pm, even though the fires had reduced considerably by this time. By 9.45 pm there were four fires still burning and two monitors operating. At 10.00 pm there was another changeover of personnel. Lay replaced Haynes as IMT operations officer and Langridge relieved Sherry as incident controller. The IMT continued to implement the strategy of isolation and containment. The problem of the identification of pipes for isolation was further discussed between IMT and Esso management, but the same policy was continued.

7.68 The bodies of Wilson and Lowery were removed at 5.20 pm on Saturday, 26 September by the CFA with police assistance. By this time, safe access to the bodies was possible. Although the last fire was not extinguished until late in the afternoon on Sunday, 27 September, it was felt that the adverse psychological impact which the presence of the bodies might have had on Esso personnel, warranted their removal. At 6.15 pm on 26 September, the bodies were taken to the mortuary at the Institute of Forensic Science in South Melbourne.





*Figure 7.17 Photograph taken at approximately 15:00, 26 September, fire still burning from GP905*

### **27 SEPTEMBER (SUNDAY)**

- 7.69 The use of a crimping tool to isolate fuel sources was first discussed by the IMT and Esso management at a meeting which commenced at 8.24 am on Sunday, 27 September 1998. At this time Jones had relieved Langridge as incident controller. Full isolation of the inventory feeding the fire still had not been achieved. There was a small, slow-burning fire still emanating from a 50 mm gas supply line in the piperack. Various options were discussed at the meeting and an Esso employee suggested pipe crimping as one option. Jones adopted this suggestion and gave approval for the work to be done. The necessary equipment was not on site and Esso engaged a contractor to do the work.
- 7.70 The police offered to transport the crimping tool to Longford, but Esso advised that it had arranged for its transportation by the contractor and that it would be on site by lunchtime. It did not arrive until 4.10 pm that afternoon. By 5.30 pm the 50 mm pipe was crimped and the last fire was extinguished. A 40 mm pipe was also crimped because it had a minor gas leak. Gas detectors were placed around the ROD/ROF area to determine whether there any residual leaks. By 8.10 pm it was established that all leaks had been stopped.

## ***FIREFIGHTING SYSTEMS***

- 7.71 The emergency protective systems in place at Longford at the time of the accident which were designed to control such an event included the Emergency Shut Down system (ESD-system), the firewater system and passive fire protection of the supports to the overhead piping. The ESD system is discussed in Chapter 8.
- 7.72 The water supply to the fire ring main at Longford consisted of three groundwater bores (or wells) from which water was pumped to five storage tanks on the site. These tanks when 90% full had a capacity of 6,296 kl. Bore pumps were used to fill the tanks. There were three electric pumps and three backup diesel pumps. There was also a dam at the southern end of the plant, known as the south pond, which could be used if necessary as an additional source of water.
- 7.73 The water from the tanks was fed into a fire mains system which ran underground throughout the entire Longford site. Bearing in mind that the various plants at the Longford site were designed and constructed over a period of 14-15 years, the firewater system was well integrated between the various plants at the site. The fire ring main was pressurised by a total of eight pumps. Four pumps were electrically driven and four pumps were driven by diesel motors as a backup should the electricity fail. The fire ring main supplied risers or hydrants in the plant to which hoses could be attached to take water from the mains. In addition, there were fixed and portable monitors with a 360 degree rotation that could be used to direct water at a fire. The fire ring main also supplied the fixed water deluge system on the LPG accumulators located within GP1. The fire mains system was designed with the capacity to supply water to the deluge system on the LPG accumulators and to use five or six monitors to fight a fire at the same time.

## ***INJURIES***

- 7.74 The explosions and fire at Longford not only caused two fatalities, but also injured eight other workers who were in the vicinity of the accident. Heath Brew was the most severely injured in the blast. He was admitted to the Alfred Hospital Burns Unit in Melbourne with severe burns to his head, face, chest and legs. He also suffered a fractured femur. Ian Kennedy was admitted to the Royal Eye and Ear Hospital with eye and ear injuries and burns to the face. He was released on 28 September. Greg Foster suffered fractured ribs, smoke inhalation, burns and abrasions and was released from Gippsland Base Hospital on 28 September. Mike Shepard and John Wheeler suffered burns and abrasions and were released from hospital on 26 September. Jim Ward, Bill Visser and Marty Fahy were all treated for distress and smoke inhalation and sent home on 26 September.



# Chapter 8

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## THE LOSS OF GAS SUPPLY

### *THE SHUTTING DOWN OF ALL GAS PRODUCTION FACILITIES*

- 8.1 The explosion and fire in GP1 at 12.26 pm and the subsequent activation of ESD1 closed the inlet gas valves to the slugcatchers, thus isolating the supply of gas to all three gas plants. The offshore platforms were shut down automatically following the ESD activation. Requests from the platform operators to go into bypass mode to allow them to keep the machinery on line were refused because of the situation in GP1.
- 8.2 As stated in Chapter 7, at about 12.45 pm, the escalation of the fire in GP1 brought about a decision to withdraw all non-firefighting personnel from the Longford site, and GP2 and GP3 were shut down.

### *THE RELATIONSHIP AND INTERCONNECTION OF PROCESSING FACILITIES*

- 8.3 To understand the problem of isolating the gas and liquid fuels which continued to feed the fire in GP1 for some 53 hours after the initial rupture of GP905, and the time needed to isolate GP2 and GP3 effectively from GP1 and the CSP before the undamaged gas plants could be safely restarted, it is necessary to examine the relationship and interconnection of all the processing facilities at Longford.
- 8.4 GP1 and the CSP were constructed during 1968 and 1969, with GP1 commissioned in March 1969 and the CSP later in the same year. The design of GP1 was commenced by Hudson Engineering before the discovery of oil in Bass Strait. Before that design was complete, Halibut Field was discovered and Hudson Engineering was then contracted to integrate the design of the two processes. This was achieved in the following way. The gas produced during the stabilisation of oil in the CSP was to be compressed and delivered to GP1 for processing. The gas liquids produced in GP1 were to be stabilised in the Product Debutanisers of the CSP prior to dispatch to Long Island Point. Separate but linked propane systems, power gas systems, flare systems and electrical systems allowed one plant to back up the other in the event of an outage of these services in any one plant. A single control room housed the control systems for both plants.

- 8.5 The design of GP1 had to take account of the role of that plant as the sole supplier of natural gas to Victoria at that time. Consequently, a good deal of duplication of vital equipment was provided to ensure security of supply. This allowed pressure vessel inspection and other maintenance tasks to be performed without shutdown of GP1.
- 8.6 When GP2 was constructed between 1974 and 1976 it was located 275 metres (900 ft) to the east of GP1, thus providing security in the event of a major incident in either facility.
- 8.7 GP2 uses an expander process for cryogenic removal of liquids from the gas stream and therefore is quite different to GP1 in many respects. However, it also has a number of common functions with GP1 which were interconnected to enhance security of gas supply.
- 8.8 Both plants use molecular sieves for dehydrating and sweetening the inlet gas (i.e. removing the sulphur compounds) and these were interconnected. These molecular sieves also have similar regeneration circuits which are interconnected to provide back up to each other.
- 8.9 Both plants also have a section for processing the hydrocarbon liquid stream entering the plant from the slugcatchers. The Crude De-ethaniser GP1106B in GP1 and the Feed Liquid Stripper GT1102 in GP2 both serve this function and are cross connected to provide backup for each other.
- 8.10 Similarly the Product Debutaniser GT1113 in GP2 and the two Product Debutanisers CS1112A and B in the CSP (physically located in GP1) are interconnected for enhanced operating security.
- 8.11 In addition, both GP1 and GP2 require the CSP to be in operation to enable the bottom product from the debutanisers to be blended into the main stream of stabilised crude oil from the CSP and pumped to Long Island Point by the four crude shipping pumps.
- 8.12 GP2 is independent of GP1 for all critical activities and services, but does rely on the KVR compressors in GP1 to compress the small quantity of low pressure gas from the overhead of the Feed Liquid Stripper, GT1102. When this service is not available, this vapour stream has to be flared, as was done after the restart of GP2 on 4 October 1998 until the recompressors were brought back into service when the CSP was restarted in December 1998. All other facilities and services, including the control rooms of GP1 and GP2, are independent of each other to ensure reliability.
- 8.13 Because the expander process used in GP2 could more efficiently recover ethane from the hydrocarbon condensate than the lean oil process in GP1, a transfer line was installed in the

early 1990s to enable the transfer of condensate from the GP1 absorbers to the GP2 Demethaniser.

- 8.14 GP3 was constructed during the period 1980 to 1983 and commissioned in February 1983. It is built adjacent to GP2 and shares the same control room. Like GP2, GP3 uses an expander process for the cryogenic recovery of gas liquids.
- 8.15 The interconnections between GP2 and GP3 are limited to a shared regeneration gas system (which is situated in GP3) and shared gas liquid processing facilities, the Feed Liquid Stripper GT1102 and Product Debutaniser GT1112, both of which are in GP2.
- 8.16 Thus, GP2 and GP3 have some interdependency but GP3 does not depend on GP1 for any services nor does GP1 depend on GP3 for any services.
- 8.17 There are a number of other connections to common facilities and utilities which complicate the complete isolation of any one gas plant quite considerably. These include:

**Connections to the Slugcatchers.** All three gas plants take their feed from the common header at the northern end of the slugcatcher barrels. Valves enable individual plants to be isolated for routine purposes, but extra isolation is required for long term shutdown of a plant.

**Connections to Slugcatcher Liquids.** GP1 and GP2 each have a connection to the base of the slugcatchers to allow processing of hydrocarbon liquids from that source. There is also a direct connection to the CSP which required isolation after the accident.

**Slugcatcher Water Phase and Other Separator Dumps.** The water/glycol phase at the base of the slugcatchers is at high pressure and discharges into GP1117 which is at atmospheric pressure. This vessel is known as the “boot” and also receives small quantities of liquid dumped from the Inlet Separators of all three gas plants and some compressor suction scrubbers in all four process units.

**GP2 and GP3 Startup Line to GP1.** This allows the off-specification gas produced during the chill down period of a startup of these plants to be reprocessed through GP1 to avoid flaring.

**Treated Gas Tie.** This allows sweet dehydrated gas (without sulphur compounds) from the molecular sieve sections of each gas plant to be distributed to any other gas plant.



**KVR Vapours to GP2 and GP3.** GP1 is the plant in which KVR gas is normally processed but that stream can be diverted to GP2 or GP3 if necessary.

**Utilities (Electricity, power gas for ESD valves, instrument air, water and propane refrigerant).** Each gas plant is self-sufficient in the provision of these utilities, but for security of supply and efficient operation they are also interconnected. Longford plant generates its own electric power and exports up to 10MW to Eastern Energy. If the Longford generators shut down, power flow is instantly reversed and the plant is supplied from Eastern Energy.

**Flare System.** GP2 and GP3 have independent process flare systems, neither of which is connected to GP1 or the CSP. They are also independently connected to the Longford massive flare system which is capable of disposing of the total inlet gas flow. They were disconnected after the accident in September.

**Stabilised Crude Fraction to CSP.** The bottom product from the Product Debutaniser in GP2 (GT1113) has to be transferred to the CSP for blending with stabilised crude oil. The line which carries this product was fire damaged and an alternative line, the “black snake”, was built at ground level to allow GP2 and GP3 to restart. Testing of the damaged line indicated that it was still serviceable so there are now two available routes for debutaniser bottom product from GP2 to the CSP.

8.18 Because GP1 and the CSP were designed and constructed together, they are intimately linked and share many interconnections and common systems. The principal ones are:

**The Control Room.** Although the process control instrumentation for the two plants is separate, the control room services such as power supply, air conditioning, and communication facilities are common.

**Propane Refrigeration System.** The two plants share a common propane refrigeration system. If the KVR compressors, which provide refrigeration for GP1, shut down, the turbo compressors of the CSP continue to supply some refrigeration to GP1, enabling it to produce specification gas.

**Product Debutanisers.** The Product Debutanisers CS1112A and B serve both plants. The bottom product from the Condensate De-ethaniser GP1106A, and the overhead product from the ROF are both fed to the debutanisers as are the bottom streams from the two CSP De-ethanisers CS1110 and CC1110. In addition, the GP2 and GP3 demethaniser bottom stream and GP2 Feed Liquid Stripper bottoms can be

directed to the Product Debutanisers, allowing the debutaniser in GP2 to be taken out of service without shutting down those plants. Geographically, the Product Debutanisers are located on the southern area of GP1.

**Raw LPG Storage and Pumping.** The LPG produced from the overhead of the CSP Product Debutanisers is condensed in propane chillers and then transferred to raw LPG storage vessels (LPG accumulators) before being pumped to Long Island Point. These vessels are in the south-eastern sector of GP1, as are the LPG pumps which deliver to Long Island Point. In an emergency situation, LPG can be re-injected into the Barracouta gas reservoir using LPG injection pumps installed in GP1. A dedicated line is available for this purpose. An interconnection is also provided between the GP2 LPG accumulators, GP1 and the CSP accumulators. This is to enable LPG from GP2 and GP3 also to be directed to storage in the Barracouta field if required.

**Vapour Recompression Facilities.** The stabilisation of crude oil in the CSP produces a gas stream which contains a significant proportion of LPG and crude oil fractions, as well as hydrogen sulphide and water vapour. This stream contains more heavy hydrocarbon components than the raw inlet gas stream from offshore. Several low pressure gas streams are produced in GP1 and GP2 during the processing of slugcatcher condensate (called crude) and raw gas. In GP1, these streams originate from the Crude and Condensate De-ethanisers GP1106A and B, Crude and Condensate Flash Tanks GP1105A and B, Rich Oil Flash Tank, GP1108 and Oil Saturator Tank GP1110. In GP2, the Feed Liquid Stripper, GT1102, produces such an overhead gas stream. All of these streams contain valuable LPG components and some contain crude oil fractions as well as hydrogen sulphide and water vapour. These low-pressure gas streams are combined as feed to the GP1 vapour recompressors, consisting of two large reciprocating compressors, one smaller reciprocating compressor (KVR) and two centrifugal compressors, all in parallel. The two large reciprocating compressors GP301B and C are Ingersoll Rand KVR units and give their name to the recompressed gas stream which is known at Longford as KVR gas. KVR gas can be directed to GP2 and GP3, but it is preferably processed in GP1 because of its higher temperature and richer composition than raw inlet gas. These characteristics are better suited to the lean oil absorption process than the cryogenic process used in GP2 and GP3.

**Power, Utilities, Flare and Drain Systems.** There are numerous interconnections between GP1 and the CSP with respect to electrical power, fuel gas, power gas, water supply, instrument air and flare systems. The flare and draining systems have also been interconnected.

- 8.19 GP1 and the CSP can operate independently as illustrated by the restart of the CSP in December 1998 with GP1 remaining shut down. However, before the accident, a number of the interconnections were being regularly used to enhance the reliability of the gas supply and crude oil production.
- 8.20 The interconnections between the processing units at Longford together with the policy of providing built-in spare equipment has proved successful in maintaining a secure supply of sales gas for Victoria for almost 30 years. The ability to transfer services and intermediate products between processing units has enabled gas production to be maintained despite equipment failures and maintenance requirements.
- 8.21 Unfortunately, however, these features complicated the process of extinguishing the fire in September 1998 and extended the time required to make the isolations necessary to allow GP2 and GP3 to be safely restarted after the fire was extinguished.

### ***THE ISOLATIONS NEEDED TO EXTINGUISH THE FIRE***

- 8.22 The ESD system was designed to close a number of battery limit valves (known as ESD valves) on the pipelines from the offshore platforms which fed the Longford plants as well as on the Sales Gas line, the LPG line and crude oil line to Long Island Point. There were various stations located in and around GP1 from which the ESD system could be activated. The most prominent station was outside the door of the GP1/CSP control room building. Once activated, these valves prevented further gas or oil from entering the Longford plants.
- 8.23 The ESD system was designed to shut down certain equipment in GP1 including the GP502A and B reboiler heaters, the GP501A and B reboilers, the AX502A and B Regeneration Gas heaters, the GP1201 A, B and C pumps and the GP1204 A, B and C pumps. It was also designed to close ESD valves on the regeneration gas inlet to AX502A and B and the ESD valves in the suction lines to Hot Oil Heater Pumps AX1201A and B, and to shut off the fuel source to the hot oil heater, AX501.
- 8.24 On 25 September the ESD system operated as designed. In this way, the activation of ESD1 immediately after the rupture of GP905, effectively isolated GP1 from all major external sources of fuel. This included the isolation of the slugcatchers from the offshore pipeline

system and the isolation of GP1 from the slugcatchers themselves. It also isolated GP1 from the outgoing sales gas system ensuring no feedback of fuel from that source. ESD1 also closed the condensate line from the slugcatchers to the hydrocyclones, shutting off feed to the crude de-ethaniser system. The overhead vapour from the Inlet Liquid Stripper in GP2 was also shut off.

- 8.25 Within GP1 itself, all of the main process pumps were automatically shut down as were the LPG Booster Pumps and the Gas Lift Compressor, which despatched processed gas to the Perch/Dolphin wells to assist oil production. The Lean Oil Reclaimer and the equipment for sweetening and drying the regeneration gas for the molecular sieves were isolated and their pumping systems shutdown. The activation of ESD1 automatically activated ESD2, which tripped all the fired heaters, shutting off both fuel supply to the burners and the process flow through the heaters. The associated process pumps were also tripped electrically.
- 8.26 ESD3 was also automatically activated by ESD1, tripping the KVR compressors. The suction and delivery valves on the compressors were automatically closed, both on the gas lines and on the propane refrigerant lines. The KVR compressors compress both of these gas streams.
- 8.27 At about 12.50 pm, the CSP was shut down by the activation of ESD-S1. This also activated ESD-S2 and ESD-S3, isolating all inlet and outlet streams from the CSP and shutting down all fired heaters and electric motor drives within the plant.
- 8.28 In his evidence, Cumming said that he swung all the handles on the GP1 ESD system with the exception of the generators. This would have activated ESD-1A and ESD-1B, which were not activated by Ward. The ESD-1A and 1B system closed valves on the inlet and outlet gas lines on the absorbers and opened a crossover from the treated gas line into the residue gas line. If required, this would have allowed treated gas to be fed into the sales gas line. It should be observed that the generators eventually shut down although the cause and timing are unknown. One consequence was the failure of the electric fire pumps.
- 8.29 The isolations made by the ESD systems were generally effective, although there was leakage through some valves which ultimately had to be sealed off by other means. However, the inventory in the ROD/ROF system was not isolated within the major vessels by any ESD valves and the contents of the ROF were ultimately fed back into the base of the ROD and out to the fire, probably through the leaking tubes in GP922 and the LC10 valve.
- 8.30 The series of explosions which occurred in the first hour and a quarter following the rupture of GP905 were caused by the failure of pipes on the piperack because of flame

impingement. Even though many of these pipes were isolated at both ends by closed valves, the inventory of gas or liquid trapped in the lines was discharged into the fire, increasing its size and intensity. A reconnaissance of the fire area by Esso and CFA personnel at about 3.40 pm indicated that the fire was still out of control, but the size of the fire emanating from the ruptured end of GP905 showed that the bulk of the lean oil had by then been burnt.

- 8.31 Manual isolations of all the interconnections between the CSP and GP1 were carried out, commencing at 4.00 pm. The CSP gas off-take system to the KVR compressors and several other liquid and vapour lines were closed off. Within 15 to 20 minutes, the fires reduced to less than half their previous intensity.
- 8.32 At approximately 5.00 pm, the liquid dump lines from the KVR scrubbers were blocked in, as was the LPG tie between GP2 and GP1 which was thought to be leaking. Further isolations were made on both absorber bottoms, Rich Oil Flash Tank vapours and Oil Saturator Tank vapours, all of which were thought to be feeding the fire through failed pipes.
- 8.33 At 6.40 pm a fresh team of shift members undertook the depressuring of the section of plant upstream from the absorbers, which had gas trapped in it, by the closing of several ESD valves when Cumming actuated ESD-1A and 1B.
- 8.34 At 6.50 pm the gas valve on the tie between GP1 and GP2 was manually closed, after which all personnel were withdrawn from the fire scene back to the fire shed prior to shift change.
- 8.35 Isolation checks continued, using the night shift personnel who arrived at 7.00 pm. By this time the fire was largely under control. The main concern was a fire on the level transmitter on the Condensate Flash Tank, GP1105A, which was impinging on the vessel's pressure control bypass line. It had started leaking. It was decided to flare the gas from both de-ethaniser systems and the KVR suction line from them. This was completed without incident and the depressuring resolved the problem of the fire on GP1105A.
- 8.36 Extinguishing the remaining fires involved identifying smaller damaged lines, sealing minor leaks at isolating valves and isolating leaks from the ruptured flare system. The flare system was not fitted with any valves because of its critical function in the disposal of vented gas. It was ultimately the nuisance fires on the damaged flare lines which proved difficult to isolate and these eventually had to be mechanically crimped to extinguish the fire completely.

- 8.37 Damage to the GP1 control room by acid fumes emanating from burnt pvc insulation required the establishment of a new control room. This, together with other modifications made necessary by the damage to services in the Kings Cross area, delayed the restart of the CSP until early December with a consequent interruption to production of crude oil.

### ***OBSERVATIONS***

- 8.38 From the evidence set out in Chapter 7 and from the modelling undertaken by the Commission's investigation team the following matters are apparent.
- 8.39 At the time GP905 failed, 22,000 kilograms (22 tonnes) of hydrocarbons were contained within GP1. Within a minute of the rupture of GP905, up to 10,000 kilograms (10 tonnes) of hydrocarbons were released to atmosphere through the rupture area. Another 12,000 kilograms (12 tonnes) of hydrocarbons were still contained within GP1.
- 8.40 Depending upon the rate at which inventory was being released through the aperture of GP905, 12,000 kilograms of hydrocarbons was sufficient to fuel a jet fire from GP905 and GP922 for up to two hours following the initial release, indicating that the fire was ultimately fed from sources outside GP1.
- 8.41 Within 30 minutes of the rupture of GP905, the jet fire emanating from that vessel and GP922 had impinged sufficiently on the piping in the east/west piperack to cause some of those pipes to fail. The failure of these pipes released new sources of inventory to atmosphere. This increased both the number and location of fires that had to be contained, complicating the task of those responding to the emergency.
- 8.42 The first of the major pipe ruptures in the east/west piperack occurred at about 1.00 pm and resulted in the explosion recorded by the security video camera (see Figure 7.2 to Figure 7.4).
- 8.43 Further explosions occurred at about 1.26 pm and 1.35 pm. These explosions, also clearly recorded by the security video camera (Figure 7.5 and Figure 7.6 to Figure 7.10 respectively), were the consequence of continuing ruptures of pipes in the east/west piperack. The failure of these pipes provided further sources of fuel mainly from the CSP.
- 8.44 The dramatic increase in the size of the hydrocarbon-fuelled fires and the intensity of the heat from those fires made the failure of further pipes inevitable, despite the efforts of operations personnel to cool the piperack by directing water from firefighting appliances into the area.

- 8.45 The ESD system was activated by Ward immediately after the initial explosion. Cumming also attempted to activate the ESD system. Once that had been done, the only feasible option available to personnel fighting the fire, was to endeavour to isolate the fuel sources to the fire and to use the available water from firefighting appliances to cool the pipes and vessels most exposed to the flames and heat.
- 8.46 The immediate action taken by the operations personnel (Visser, Cumming and others) to set up and direct ground monitors was therefore appropriate. The escalation of the fire that subsequently occurred was not due to any failure by them to act in an appropriate manner but rather to the design limitations of the ESD system in GP1.
- 8.47 Although there was no formal identification of the Incident Response Group designated by the Esso Emergency Response Manual, those personnel available in GP1 at the time of the accident performed the functions of such a group. Their attempts to isolate the plant, rescue the injured and initiate fire suppression measures were not only wholly appropriate but, in view of the personal danger which they faced, also heroic.
- 8.48 The death of Peter Wilson temporarily left the Incident Response Group without leadership. However, Hiskins quickly took over this role, with Visser in the role of forward controller.
- 8.49 There was an unnecessary delay between the occurrence of the fire and the time that the CFA were first notified. Moreover, it appears that when the CFA did arrive at Longford, security staff at the entrance gate were not sufficiently cognisant of the importance of ensuring that CFA personnel were granted immediate access to the site. This lack of understanding reflected a shortcoming in communications between Esso plant management and security staff. It also highlighted a shortcoming in security staff training in emergency response procedures. Most importantly, it contributed to an unnecessary, albeit temporary, breakdown in communications between Esso personnel and CFA personnel. In a serious accident, such as occurred on 25 September 1998, time lost can sometimes be measured in lives or serious injuries. Fortunately, on that day, it appears that these matters did not seriously hamper or delay the suppression of the fire.
- 8.50 The ESD system in GP1 was designed only to isolate the Longford plant from the major offshore pipelines, and the feed to the gas transmission line. It did not activate any isolation valves, apart from a valve on the dehydrators, within GP1. The consequence was that the entire volume of hydrocarbons contained within GP1 vessels and interconnecting piping existed as an uncontrolled source of fuel for the fires emanating from GP905 and GP922. In particular, the large inventory of lean oil in the ROF was not isolated by the operation of the

ESD system. There were automatic isolation valves on the suction lines to each of the GP1204 pumps, but these were only activated by the failure of the pump seals and not by the ESD system. This weakness was recognised by a 1994 Periodic Risk Assessment (PRA) of GP1, but it appears that no action was taken to correct the situation.

8.51 Another of the areas of criticisms set out in the 1994 PRA conducted for GP1, concerned the general status of the ESD system. In particular, the PRA stated that the ESD system was not well documented or disseminated and depended for its integrity almost entirely upon human action. The PRA recommended that the ESD system be considered in the forthcoming HAZOP for GP1 which was to take place in the following year (but which did not eventuate). Moreover, during a 1995 HAZOP of the CSP, the HAZOP team experienced difficulty in obtaining a clear understanding of the ESD system in that plant and made criticisms of the ESD system similar to those made in the 1994 PRA of GP1.

8.52 The design of the ESD reflected the standards of industry practice in the late 1960's and early 1970's. However, an ESD system designed in accordance with common practice today would have divided GP1 into sections based upon major inventory groupings and would have provided shut down valves for each of these sections. Even a modern ESD system would not, however, have prevented the initial release of 10,000 kilograms of hydrocarbons that immediately followed the rupture of the GP905 exchanger.

8.53 Modern design would almost certainly require a critical pipeline junction such as Kings Cross, to be assessed and analysed for risk associated with fire and explosion damage to pipes such as occurred in the ROD/ROF area. Isolation and depressurisation systems would also be required to minimise the risk of an accident such as occurred on 25 September 1998.

8.54 Had the supply of flammable materials been isolated within minutes after GP905 ruptured, it is unlikely that any of the pipes in the piperacks would have failed as they did. Once some of the major pipes in the Kings Cross piperacks failed, additional sources of material were available from outside GP1 to fuel the fire. The availability of these further sources to fuel the fire completely changed the dimension and scale of the accident. Apart from complicating the task of making the necessary isolations, it generally increased the size and intensity of the fire and thus the dangers to operations and firefighting personnel. It also generally increased the likelihood of damage occurring which was serious enough to threaten the integrity of GP1. Moreover, the location of the east/west piperack and the nature of its pipeline inventories made it almost inevitable that damage which threatened GP1 would also threaten interconnections between GP2, GP3 and the CSP thus threatening the whole of Victoria's supply of natural gas.



8.55 The lack of a pre-planned set of isolations for GP1 meant that pipe and vessel isolations had to be conducted on the run and then tested in a highly dangerous environment. The difficult task of developing the necessary isolation plans took valuable time. It also took time to verify the plans by testing them in the field, before isolations could be finally effected. The time taken to carry out this work was the primary reason why it took days rather than hours to extinguish the fire.

# Chapter 9

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## THE RESTART

### *COMMENCEMENT OF TASK*

- 9.1 The task of restarting GP2 and GP3 commenced on Friday, 25 September 1998 with the deployment of experienced personnel from Esso's Melbourne office to form a gas restart team. This team was assigned the responsibility of developing plans for the restart of gas supplies. A number of Longford personnel were added to the team together with other experienced Esso engineering personnel who were requested to report to Longford on the morning of Saturday, 26 September.
- 9.2 Esso senior management recognised that the resources needed for the gas restart activities were beyond those available within Esso. Arrangements were made to recall experienced former Esso personnel from overseas assignments and to obtain the assistance of experienced employees from other Esso affiliates outside Australia. Most of these people arrived in Australia within 3 days and were deployed to Longford.

### *ISOLATION FROM GP1*

- 9.3 By the early hours of Saturday 26 September, the gas restart team had concluded that the isolation of the slugcatchers and GP2 and GP3 from GP1 would provide the fastest method of initiating a restart and had identified the steps needed to do this. These were:
- isolate GP1 from the slugcatchers' flare relief system. Although the slugcatchers have a separate pressure relief header from that of GP1, GP2 or GP3, it is normally connected to the GP1/CSP flare and burn pit system. As a consequence, the gas restart team determined that valves would need to be manipulated to facilitate the segregation of the slugcatchers' flare relief system from GP1. The GP1 flare system needed to be directed to the standby GP1 high pressure flare stack. It was recognised that scaffolding would be required to gain access to some valves.
  - isolate GP1/CSP from the boot system. Many slugcatcher, GP1 / CSP and GP2 and GP3 drains and/or separator and scrubber dumps discharge to the boot. As it was not known whether the GP1 lines entering the boot system had been damaged in the accident, plans were established to isolate these lines from the boot.

- re-establish GP2 and GP3 power gas supply. High-pressure power gas is required for operation of the ESD valves in GP2, GP3 and the slugcatcher area. Following the total gas plant shutdown of the Longford plants, power gas could be obtained by backflow from the Transmission Pipelines Australia Pty Ltd (TPA) pipeline. As the pipeline pressure had declined and could not be guaranteed at that time, work was initiated to install a backup supply of high pressure power gas, using several nitrogen cylinders at each valve.
- supplement electrical power supply to GP2. Although GP2 had enough electrical power available from Eastern Energy to supply the control room, Longford was not supplied from that source with sufficient power to operate an entire plant such as GP2. The GP2 generators would normally operate using plant fuel gas, and power supply from Eastern Energy would not be required. However after a total plant shutdown fuel gas would have to backflow from the TPA pipeline and this could not be assured. Therefore additional power was required and approval from Eastern Energy to connect to its grid was sought and gained late on Saturday evening.

9.4 The gas restart team set up an isolation team to identify all of the isolation points that would be required to effect a safe restart. This was a complex task which involved an intimate knowledge of the plant and a detailed examination of the P&IDs for all four production units. Over a period of a week this resulted in the marking up of some 200 P&IDs showing where isolations were needed. This information was also tabulated, with a description of the service to be isolated, the valve involved, the type of isolation required and the person required to check the isolation when complete. A tag number was used to identify each isolation and this number was shown on both the relevant P&IDs and the tabulation. The tabulation for GP1 isolations to GP2 and GP3, which is shown in Appendix 2, lists 93 valves, several of which were required to be reopened, having been shut during the initial isolation of GP1. This left 85 isolations to be completed in order to fully isolate GP1.

*Table 9.1 Summary of Isolations*

Isolation Area	Number of Isolations
GP1 Isolations to GP2 and GP3	85
CSP Fuel Gas and Power Gas Isolations	72
GP1 Boot System	4
GP2 Debutaniser to CSP via Surge Tanks	82
Propane Systems Isolations	19
Miscellaneous	7
<b>Total</b>	<b>269</b>



- 9.5 A number of electrical isolations were also needed, although most of the electrical circuits in GP1 could be isolated by opening circuit breakers on main distribution boards.

### ***DEVELOPMENT OF A PLAN***

- 9.6 By Saturday, 26 September, the gas restart team had proposed a preliminary plan to bring back into service the molecular sieves and associated equipment in GP2. This would enable rich gas (dehydrated and desulphurised, but still containing ethane, propane and heavier components) to be delivered to Gascor to satisfy its request for the provision of rich gas as soon as possible.
- 9.7 Under this proposal, the condensate arriving with the raw gas at the slugcatchers would be dumped to the slugcatcher Condensate Vapour Disengagement Drum SC1103, from where the vapour would be flared and the liquid sent to the burn pit. As this would result in the production of an unacceptable amount of black smoke, the team was requested to investigate other options.
- 9.8 By Saturday evening, the gas restart team had developed a plan for a full restart of GP2 and GP3 to produce specification gas and to despatch both LPG and stabilised hydrocarbon liquids to Long Island Point. Existing equipment enabled LPG to be pumped from GP2 to Long Island Point, but the disposal of the stabilised liquid from the bottom of the Debutaniser to the crude oil pipeline to Long Island Point required special attention.
- 9.9 The existing transfer line from GP2 to the CSP for the GP2 debutaniser bottoms stream passed through the southern part of GP1 (not Kings Cross) and had been found to be at least superficially damaged by the fire. As the integrity of this pipeline was in question, the black snake was proposed. This has been referred to in Chapter 8. Design work commenced on this black snake pipeline on Sunday 27 September. Materials and equipment were quickly found and detailed design rapidly progressed. Arrangements were made to install on the pipeline a pump purchased for an offshore project to boost the pressure and thus increase the flow rate of debutanised liquid into the Long Island Point crude oil line. As an alternative, work also began on the design of pipework to allow the CSP C-train de-ethaniser reflux pumps to be used to boost the GP2 debutaniser bottoms product into the crude pipeline.
- 9.10 To reduce the amount of condensate to be handled at Longford, a decision was made to use Barracouta gas in preference to Marlin gas. Of the three gas sources, that of Marlin is the richest in heavier components and produces the most condensate. When Barracouta's capacity was exceeded, Snapper gas was to be used. The predicted gas demand for October would normally not require all three platforms to be producing.

- 9.11 In addition, approval was granted by the Department of Natural Resources and Energy to re-inject separated gas liquids from the Snapper platform back into the reservoir. Facilities exist on the platform to do this.

### ***PLANNED RESTART DATE***

- 9.12 On Monday, 28 September, a meeting was held between the Premier of Victoria and Esso's chairman and managing director, Robert Olsen, together with senior government and Esso officials. It was agreed at this meeting that disposal of condensate to the burn pits would not be undertaken. It was also decided to plan a restart for Monday, 5 October to allow for any unforeseen restart problems.

### ***CONTINUATION OF BLACK SNAKE***

- 9.13 Whilst the black snake was being constructed, work was undertaken to confirm the integrity of the original debutaniser bottoms line. Plans were developed to pressure test the line with water at a pressure of 1850 kPa. By this time the isolation team had identified that an additional 82 isolations were required to isolate completely the line from the CSP / GP1 process areas.
- 9.14 It was also realised that prior to recommencing processing operations at Longford it was necessary for the fire water system of GP1 to be serviceable. Several fusible plugs which activated the deluge system on the LPG accumulators had melted during the fire in accordance with their design intent and had to be replaced.
- 9.15 By Tuesday 29 September, most isolations between GP2 and GP1 were completed, although those on the debutaniser bottoms line remained to be done. The completion of the black snake was all that was required to allow GP2 to restart.
- 9.16 A surveillance plan was established for the Longford site during the initial pressurisation and startup of GP2. This was to enable double-checking of all isolations between GP1, GP2 and GP3 and the allocation of staff to cover all interconnections.
- 9.17 The original debutaniser bottoms line was tested and no external leaks were observed, but a confirmation test was planned for the following morning.

### ***REVIEW AND APPROVAL***

- 9.18 On Wednesday, 30 September, Gascor was notified of the planned introduction of gas to GP2 for testing purposes. The Victorian WorkCover Authority (VWA) and the CFA indicated that approval to restart GP2 and GP3 under s.33(2) of the *Dangerous Goods Act*

would be subject to formal review under the Longford Gas Restart Plan which was scheduled for that day.

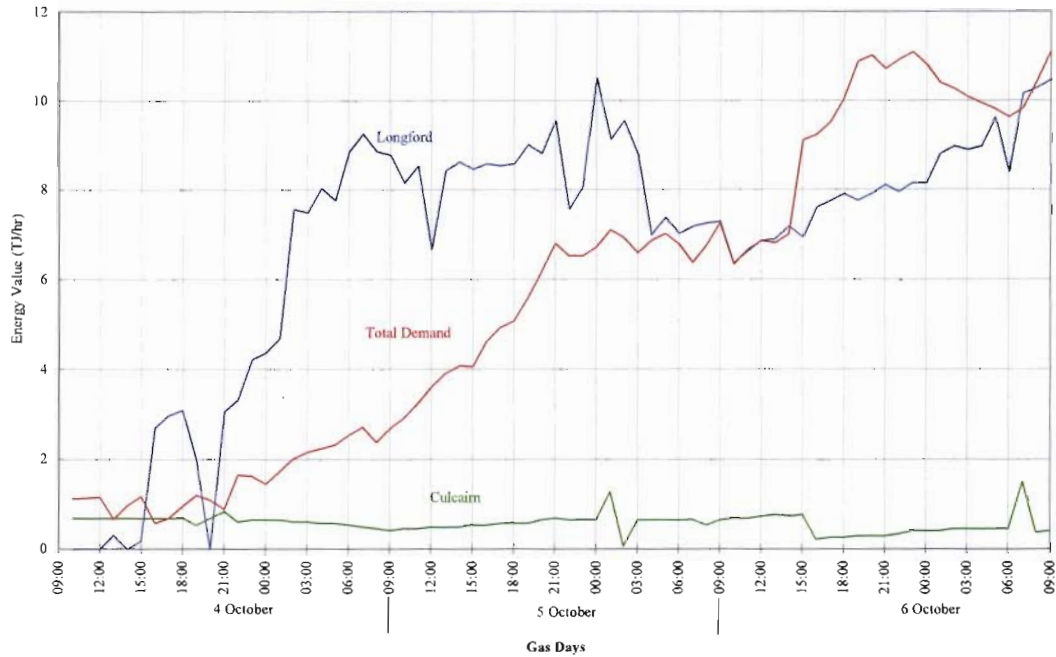
- 9.19 The planned review took place as scheduled on Wednesday at Longford and a review was also conducted by the Crisis Management Team in Melbourne. A letter was then forwarded to VWA giving Esso's assurance that GP2 and GP3 were safe to operate and requesting VWA approval for the restart.
- 9.20 Also on Wednesday, a programme of Critical Function Testing was established and testing was initiated within GP2. The connection of the black snake into the debutaniser bottoms line at the point where that line entered GP1 was carried out during the day, but this required the planned leak test on the debutaniser bottoms line to be deferred.
- 9.21 On Thursday, 1 October, notification was received from Gascor that the maximum amount of off-specification gas that would be accepted into the sales gas pipeline at Longford was 3 Mm<sup>3</sup>. Consequently the GP2 cold section needed to be cooled down and producing specification gas before Esso could begin producing significant quantities of sales gas. Much of the off-specification gas produced during cool down of the plant would have to be flared as the normal procedure of reprocessing this gas in GP1 was, of course, not available.
- 9.22 The construction of the black snake continued on schedule and, in addition, bypass pipework was installed around the Crude Shipping Pumps in the CSP to allow use of the existing debutaniser bottoms line.
- 9.23 On Friday, 2 October, a minor setback occurred when non-destructive testing on the black snake identified several welds that needed to be redone. However, this did not significantly delay preparations for restart as a number of detailed plant and administrative matters required finalisation.
- 9.24 The debutaniser bottoms line pressure safety valves (PSVs) were reset from 1467 kPa to 1850 kPa, the maximum allowable line rating, to allow the line to be operated at the higher pressure necessary to enable liquid to flow to Long Island Point without any pumping. Lower pressure-rated equipment connected to the line was also isolated.
- 9.25 A procedure for using Eastern Energy power to initiate the restart of GP2 prior to fuel gas being available for its own power generator and a procedure for the restart of GP2 after the total shutdown were approved by Longford management. Upon the final completion of the items contained in the prestart up checklist, Esso management formally approved the Longford Restart Plan.

## ***THE RESTART***

- 9.26 The VWA gave its approval to restart GP2 and GP3 under s.33(2) of the *Dangerous Goods Act*. A letter was also received from VENCORP formally asking for confirmation of the reliability of gas supply before it commenced the reconnection of customers.
- 9.27 A letter from Esso was delivered to Gascor explaining the restart plans and requesting a sales gas rate into the meter station at Longford of at least 3 Mm<sup>3</sup>/d. This was needed to ensure that the demand for gas from the Victorian system be increased in step with the deliveries of gas available from GP2 in order to achieve stable plant operating conditions.
- 9.28 With VWA and management approval for a restart having been given, it was decided to undertake a test restart of GP2 to confirm its operability and verify its isolation from GP1 / CSP. Pressuring up began about 3.00 pm on Friday, 2 October and start-up proceeded steadily until 7.00 pm when the GP1 surveillance operator smelt gas in the area and thought he observed electrical arcing from some exposed cables at Kings Cross. The test was stopped by Longford management.
- 9.29 On Saturday, 3 October, an infra-red thermographic survey failed to find any evidence of electric arcing or other electrical isolation problems. The gas smell was traced to a small leak from a fire-damaged propane cylinder in the GP1 analyser hut.
- 9.30 As the black snake was now complete, all the prerequisites for the restart of GP2 had been met and the pressurisation of the plant was recommenced at 3.45 pm. The outlet to the TPA line was opened and pressure equalised but no flow occurred at this stage. The cool down progressed through the night ready for sales on Sunday, 4 October, with off-specification gas being flared.

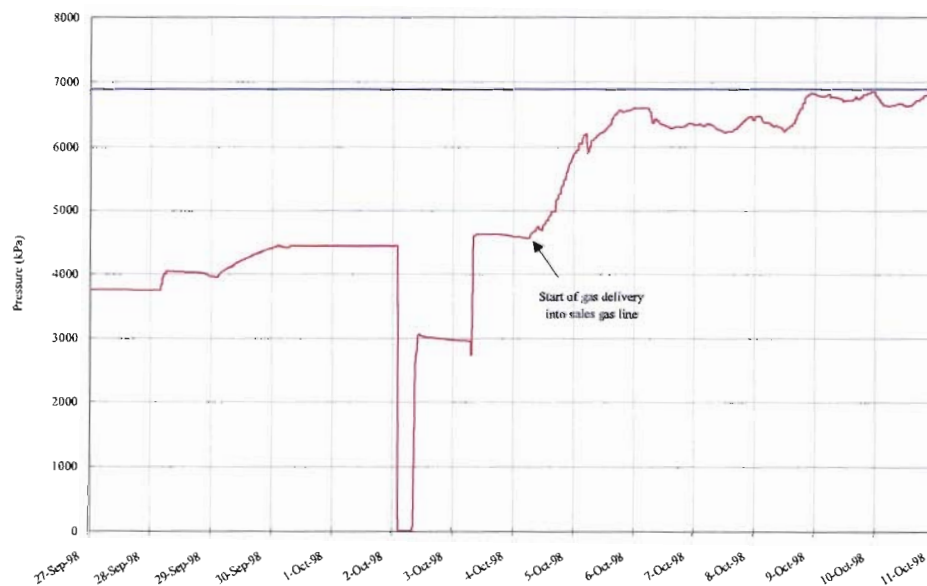
## ***COMMENCEMENT OF GAS SALES***

- 9.31 By 2.00 pm on Sunday, 4 October, GP2 was ready to supply specification-quality sales gas. Gas sales commenced at around 2.45 pm. The Gascor sales gas chart for gas days 4 October to 6 October 1998 is shown in Figure 9.1. The gas day starts and finishes at 9.00 am, which is almost universal practice in the natural gas industry.



**Figure 9.1 Gas sales for 4 October to 6 October 1998**

9.32 At the time that gas sales commenced, the pressure in the TPA pipeline was about 4,600 kPa. This is shown on Figure 9.2, which is a chart of the outlet pressure at the Longford Plant for the period 27 September to 11 October 1998. It can be seen from that figure, that the pressure rose quite rapidly following the restart at GP2, increasing to 6000 kPa by 10.00 am on 5 October and reaching a plateau of 6600 kPa by 9.00 am on 6 October. During that time, plant output peaked at 6.25 Mm<sup>3</sup>/d but for most of the time was around 5 Mm<sup>3</sup>/d.



**Figure 9.2 Pipeline pressure for 27 September to 11 October**



- 9.33 The black snake was put into service when the plant restarted on Sunday, 4 October. The line was operated in free flow using the pressure in the GP2 Product Debutaniser to deliver liquid, without pumping, to Long Island Point. However, a pump together with a portable generator was installed to enable the liquid to be pumped if higher flow rates required it.
- 9.34 Monday, 5 October was the day on which the CFA relinquished its control of the Longford site and Esso resumed formal control. On this day, GP2 continued to operate without problems with sales of gas for the day restricted to five million cubic metres by the high inlet pressure of the TPA pipeline. GP3 was started up and tested but it could not be kept running as the demand for gas was too low to allow both GP2 and GP3 to operate.
- 9.35 On Tuesday, 6 October gas sales from Longford fell to 4 Mm<sup>3</sup>/d and GP3 remained off-line for lack of demand. VENCORP issued a press release advising that all industries and businesses that were not already supplied with gas could start reconnecting to the gas system at 6.00 am Wednesday, 7 October.
- 9.36 As a result of the additional reconnections, gas demand on Wednesday, 7 October rose to 6 Mm<sup>3</sup>/d and GP3 was brought on line. Gas sales increased still further on Thursday with domestic customers being progressively connected over a two day period. Sales into the TPA line rose to 9 Mm<sup>3</sup>/d and reached 11 Mm<sup>3</sup>/d on Friday. Domestic customers were still prohibited from using space heaters.
- 9.37 The two plants continued to operate without major problems through the weekend and early part of the following week. On Tuesday, 13 October the Premier of Victoria announced that space heaters could be restarted. This restored the gas demand to the normal level for that time of the year and by 14 October 1998, the interruption to supply of gas was effectively over.
- 9.38 The restart of GP2 and GP3 was well managed by Esso. The work of isolating and restarting GP2 and GP3 was carried out under the requirements of the LWMM. Not only did the isolations between production units have to meet certain standards of safety, e.g. double block valves or double block and bleed, but all the changes to operations made necessary by these isolations had to be sanctioned by the Field Change Approval system. Sixty-seven such approvals were drafted and sanctioned. New startup procedures had to be drafted for both GP2 and GP3 to take account of changes made and new procedures had to be produced for the use of the two Debutaniser Bottoms lines (old and new). HAZOP studies were also carried out for these two lines.

- 9.39 One-off operating procedures were also drafted for GP2 rich gas to sales and for condensate handling prior to export to Long Island Point. A plan was also produced for the relighting of the flares and burn pit to which a number of connections had been changed.
- 9.40 Risk assessments were carried out on GP1 because of the open pipes, stored hydrocarbon inventory, asbestos damage and exposed electrical wiring. Assessments of structural damage to the towers in GP1 were undertaken.
- 9.41 The CFA also prepared a Longford Incident Action Plan for the restart period.
- 9.42 The changes to operating procedures and numerous organisational matters connected with the restart required a considerable number of training and briefing sessions. The scheduling of these sessions to fit in with the multitude of tasks being performed in the week prior to restart was in itself a major problem.
- 9.43 The Longford Restart Plan, a 280 page document, was reviewed by the VWA, CFA and Victoria Police at a meeting with Longford Plant Management. Copies of the document were distributed to the external parties on 1 October. Esso Management formally approved the plan on Friday 2 October.
- 9.44 The trouble free restart of GP2 and GP3 reflects the thorough manner in which safety, technical, organisational and administrative matters were addressed. In view of the complexity and magnitude of the task, it would not be reasonable for a safe and reliable restart to have been made in any shorter period.

### ***THE DELAY IN RESTORATION OF GAS TO CUSTOMERS AFTER THE RESTART***

- 9.45 It is unfortunate that after a successful restart of the Longford facilities, the full restoration of gas supply to consumers, particularly domestic consumers, took another five days.
- 9.46 The stream of correspondence between Esso/BHP and VENCORP/Gascor reveals the reason for the slow reconnection. Esso, understandably, was not able to guarantee that there would be no production problems when bringing back into service two cryogenic processing plants that had been closed down for eight days. The cold sections of these plants operate at about -80°C and the very large temperature changes which they undergo during a long shutdown and subsequent restart can lead to flange leakages and mechanical equipment problems. These plants also operate more stably at rates near their maximum designed output.

Operating them at low rates can therefore contribute to operating problems and reduce the availability of the plant.

- 9.47 VENCORP, on the other hand, was understandably reluctant to advise the government to raise the restrictions on gas use until continuity of supply could be assured. The task of restoring supply to 1.4 million domestic consumers needed the assistance of numerous gas fitters as a number of those consumers would require help in turning on supply and relighting appliances. This was obviously not to be undertaken if there was a risk of repetition because of a subsequent failure in gas supply.
- 9.48 For additional security, VENCORP also chose to continue the purchase of gas through the interconnection with New South Wales during the first few days of the restart. This was at a very low rate of less than 20 TJ/d and did not significantly impair the flow from Longford into the TPA pipeline.
- 9.49 As the days passed and the reliability of the plant was demonstrated, VENCORP progressively allowed the reconnection of more customers, culminating in the restoration of supply to domestic customers on Thursday 8 and Friday 9 October. By that time Esso was claiming that a plant capacity of 16 Mm<sup>3</sup>/d was attainable but was still not prepared to give an unqualified guarantee of its continuous availability.
- 9.50 No doubt the slow increase in sales volumes was a disappointment to the Esso personnel who had worked very effectively under considerable pressure to restore supply. In retrospect, however, it seems that reconnection of domestic customers could not have been advanced by even one day without a considerable risk, as time was needed to demonstrate the reliability of the two plants.

### ***RESTORATION OF SUPPLY FROM GP1 FOR WINTER 1999***

- 9.51 Since the restart of GP2 and GP3, Esso/BHP have met their contractual commitments for gas supply. However, those two production units have insufficient capacity in their restarted condition to meet the winter gas demand. Esso therefore implemented an extensive work programme intended to restore sufficient gas sales capacity from Longford by the end of May to meet the rising seasonal demand.
- 9.52 The strategy adopted by Esso was to provide two parallel and independent execution paths for GP1, GP2 and GP3 so that meeting the 1999 winter peak could be assured by either execution path.

- 9.53 The restart of GP1 consisted of a phased approach to allow an early increase in plant availability which would be enhanced as the three distinct phases were completed. GP1 was not restarted as a lean oil absorption plant for the winter of 1999 and no plans have been developed for its reinstatement in that form in the future. Instead the cold section of GP1 has been reinstated as a cold separation system and this should provide the required sales gas capacity. The ability of the Longford plant to produce the required volume of ethane for the petrochemical industry has not, however, been restored. This is because the temperatures that can be used in the chillers and absorber vessels are not low enough to condense a major portion of the ethane from the gas stream being processed. Even during the winter period when gas volumes being processed are at a peak, ethane production is not expected to exceed 550 t/d compared to an historic demand of 650 t/d. The discrepancy in supply will increase to about 300 t/d in mid-summer.
- 9.54 The objective of the plant modifications in GP2 and GP3 was to install additional back-up equipment capable of providing flexibility in the event of equipment failure in any of the three gas processing plants.
- 9.55 At the time of writing this report, Esso's immediate objective of securing the gas supply for winter 1999 appears to be in doubt. This is because industrial trouble has slowed the restoration projects. However, for the longer term, Esso has identified projects and allocated resources to begin addressing the issues of the restoration of full liquids recovery and future upstream supply.

### ***IMPROVEMENTS TO THE SECURITY OF GAS SUPPLY***

- 9.56 Until the restoration of GP1 provided additional capacity to process both gas and gas liquids, the ongoing supply of gas depended on the ability of the GP2 and GP3 to deal with the liquids that arrived in the slugcatchers or were extracted during the processing of the gas. The building of the black snake provided a secure means of despatching debutaniser bottom products to Long Island Point. An existing system allowed the mixed LPG product from GP2 and GP3 to be pumped to Long Island Point, but the processing of the hydrocarbon liquids from the slugcatchers after the accident on 25 September was limited to the Feed Liquid Stripper in GP2.
- 9.57 As a consequence, in the fourth quarter of 1998, piping and pumping facilities were installed to allow up to 2.1 Ml/d of slugcatcher condensate to be pumped to the Barracouta platform for re-injection into the Barracouta formation. This process used an existing pipeline which had been installed to allow LPG to be re-injected into Barracouta if Long Island Point was unable to accept it.

## ***THE PHASED RESTORATION OF GP1***

9.58 The restoration of GP1 was planned to take place in three phases.

### ***Phase 1***

9.59 Phase 1 provided for the restart of the GP1 inlet treating section. The molecular sieves and their ancillary equipment for purifying and drying their regeneration gas stream have been restored so that they are now capable of supplying desulphurised and dehydrated gas. A small quantity of this gas can be blended directly into the GP2 and GP3 sales gas stream to increase the sales gas volume. This is possible because the sales gas from GP2 and GP3 is well within the heating value and Wobbe Index specifications and a small stream of rich gas which does not meet the specifications can be blended into the sales gas stream without exceeding the specified limits.

9.60 A new tie line was built between GP1, GP2 and GP3 to enable treated gas from the molecular sieves of each production unit to be transferred between plants. This was available for use in the interim period before the completion of Phase 2. This interconnection allows GP1 treated rich gas to be fed to GP2 and GP3 even though the remainder of GP1 is out of service.

9.61 Phase 1 also recommissioned part of the GP1 slugcatcher condensate handling system. This involved the condensate heater GP921A using hot oil to warm the condensate before it was delivered to the GP1105B Flash Tank and then to the CSP for stabilisation via a new connecting pipeline.

### ***Phase 2***

9.62 Phase 2 of the GP1 restart recommissioned the gas chilling and separation section of GP1. In this phase, GP1 was modified to allow the absorbers to be used as cold separators with no circulation of lean oil to assist recover of the heavy components from the gas stream. With the completion of Phase 2, the Gas/Gas exchangers GP901A, B, C and D and the Gas Chillers GP902A and B cool the inlet gas to -15°C before it enters the Absorbers GP1104A and B. Condensate is separated in the absorbers, the bottom sections of which have been modified internally to allow the GP903A and B heat exchangers to be used to heat the condensate as it leaves the absorbers. This differs from their operation as reboilers when they recirculated the heated condensate back into the bottom of the absorbers. The warmed condensate at about 0°C is transferred through an existing pipeline to the GP2 Demethaniser for further processing. A new pipeline connection to GP3 was installed to allow condensate to be transferred to the demethaniser in that plant.

- 9.63 The GP1 propane refrigeration system was also brought back into service during Phase 2 to provide the refrigerant to Gas Chillers 902A and B.
- 9.64 The Crude De-ethaniser, GP1106B, was returned to service in Phase 2, together with its associated equipment. This restored the full capacity of the Longford plant to process slugcatcher condensate.

### ***Phase 3***

- 9.65 The work involved in Phase 3 is proceeding at the time of drafting this report. It was originally scheduled for completion by the end of May 1999 but has been delayed as noted in paragraph 9.55. The completion of Phase 3 will enable the Longford Plant to produce specification sales gas at rates comparable with the plant's capacity prior to the September accident.
- 9.66 In Phase 3, the absorber condensate processing system will be recommissioned with a number of modifications and additions to its previous format.
- 9.67 The existing processing system consisting of the Condensate Heater, GP919, the Condensate Flash Tank, GP1105A, the Condensate De-ethaniser Feed Heater, GP921A, and the Condensate De-ethaniser, GP1106A, will be supplemented by a number of additional items of equipment. A condensate separator downstream from each of the GP903A and B heaters will return the separated vapour to their respective absorbers. The conversion of the existing GP925 Rich Oil Exchanger to condensate warming service will provide additional heating downstream from GP919. The heating medium for GP919 will revert to warm propane, and the heating medium for GP925 will be reflux liquid from the CSP Product Debutaniser which was used on GP919 before the September accident.
- 9.68 Two new Product Debutaniser reflux pumps dedicated to supplying GP925 are to be added, together with two new Condensate De-ethaniser pumps dedicated to a new warm-up recycle line connected to the condensate line from the absorbers to the Condensate Flash Tank, GP1105A. When in operation, this equipment will enable the chilling of treated gas to -32°C prior to separation of condensate liquids in the absorbers.

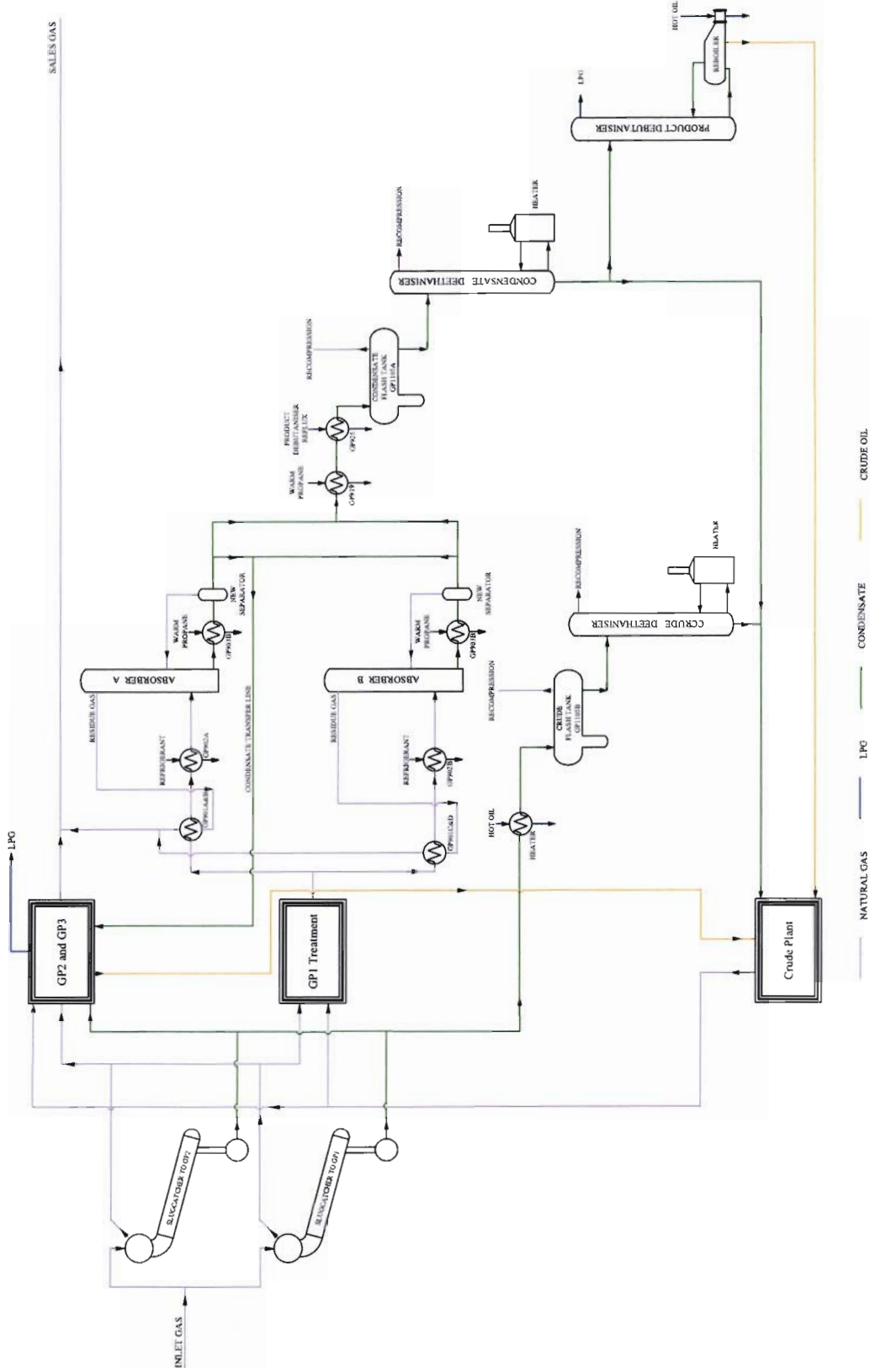


Figure 9.3 Modified GPI process after Phase 3

9.69 Figure 9.3 is a diagram of the modified process after completion of Phase 3. This process will produce sales quality gas that will flow from the top of the absorbers. The condensate leaving the bottom of the absorbers will be heated by GP903A and B to about -5°C. This mixture of vapour and liquid will flow to the new separators for removal of the vapour which will join the gas passing up through the absorber. The remaining condensate will be flashed to 3100 kPa through the absorber level control valves LY9A and B and then combined into one stream to be warmed by the two heat exchangers GP919 and GP925. After separation of vapour and liquid in the Condensate Flash Drum, GP1105A, the liquids will pass through the Condensate De-ethaniser Heater, GP921A, and enter the Condensate De-ethaniser, GP1106A. The overhead vapours from the Condensate Flash Drum and the De-ethaniser will be recompressed and returned to the inlet of GP1. The bottom product from the De-ethaniser will be fed to the Product Debutanisers in the CSP.

### ***RESTORATION OF INSTRUMENTATION, ESD SYSTEM AND PLANT SERVICES***

9.70 The recommissioning of the process units referred to above required the provision of a number of supporting services and the repair or servicing of much of the existing equipment in GP1.

9.71 The accident on 25 September 1998 resulted in severe damage to the pneumatic instrumentation and control equipment in GP1. In addition, as mentioned in Chapter 8, the GP1 control room suffered extensive damage because of the release into the room of hydrochloric acid fumes produced by the decomposition of pvc cable insulation.

9.72 An early decision was made to relocate the CSP Bailey system from the existing control room to the Offshore Support Group (OSG) building. This building is located about 250 metres from the centre of GP1 and is well outside the area affected by the fire. This allowed a faster restart of the CSP because the condition of the existing control room was no longer a consideration. A logical extension of this decision was to relocate the GP1 instrumentation in the OSG building. This precluded the further use of the pneumatic instrumentation previously used in GP1, because the distance from the plant would lead to an unacceptably slow control response. This in turn led to the decision to replace the pneumatic system with a Bailey Distributed Control System (DCS) using electronic field transmitters.

9.73 The fire also badly damaged the pneumatically activated ESD system. In view of the amount of work required to reinstate this system, a decision was made to replace it with an



electrically operated system built to current international standards. A new ESD system in GP1, including a Triconex programmable safety system, has been installed. Any system or component failure will cause the system to go to its safest state. The system can be tested without shutting down GP1. The Triconex system will also be used to provide the protective system logic. This will manage the alarm and shutdown system which protects GP1 against operating conditions outside the set parameters.

9.74 The switch gear room, and the motor starters which it contained, were damaged by the fire and the room was subsequently demolished. It has been replaced by a new building containing new motor switch gear. All the electrical power and lighting facilities for the GP1 area have been repaired or replaced.

9.75 Extensive mechanical restoration was also needed to repair the fire and blast damage on a multitude of equipment items. This included valve replacements, stripping and reinsulation of vessels and pipework and the replacement of the east-west piperack adjacent to Kings Cross. Extensive inspection of vessels and checking of pressure safety valves was also needed. In the Kings Cross area it was also necessary to close off damaged lines for water, oils and nitrogen. Numerous other maintenance jobs scheduled for the first available plant turnaround were carried out as GP1 was being prepared for restart.

### ***SAFETY ASSESSMENTS ON THE MODIFIED GP1***

9.76 At the direction of the VWA and in accordance with requirements set out in its management system, Esso has carried out three major safety evaluations of the GP1 plant.

9.77 Because of the changes that were envisaged in GP1 to meet the 1999 winter contractual obligations for gas supply, plans for a HAZOP study were initiated in early October 1998. This study was conducted in three parts, using the Exxon HAZOP technique. It was undertaken by specialists from Esso, its overseas affiliates and Australian engineering contractors.

9.78 The studies were carried out on:

- The GP1 facilities that were to be reoperated as they were originally built;
- The modifications that were called for in GP1; and
- The pre-start up conditions for the three phases.

- 9.79 These studies produced follow-up actions that required modifications to design, changes to existing facilities, new operating procedures and the additional training of operating staff. Findings were ranked into A and B categories, with A category findings having to be satisfactorily covered before the start up of the section of plant involved.
- 9.80 International consultants have been engaged to undertake a Quantitative Risk Assessment (QRA) of the Longford plants. The determined risk can then be compared with international bench mark levels and, if necessary, additional sensitivity analysis can be undertaken to calculate the impact of potential risk reduction measures. These studies require complex mathematical modelling. They are scheduled to be completed in October 1999.
- 9.81 A fire safety study has also been initiated to assess whether the existing fire detection, prevention and mitigation systems provide adequate protection. The study will involve a review at the fire hazards within the Longford plants to determine credible fire scenarios. These scenarios will be used to determine the effectiveness of fire controls and safeguards and the physical facilities available for fire detection and firefighting.
- 9.82 The fire safety study is expected to be completed by June 1999.
- 9.83 Esso initiated a metallurgical study of all pressure vessels in the chilldown and absorber sections of GP1. This was made necessary by its intention to operate these sections at a somewhat lower temperature than was the case prior to the September accident. The studies determined the Minimum Design Metal Temperature (MDMT) for each vessel using draft design standard API 579, "Recommended Practice for Fitness for Service". The MDMT is a metallurgically determined minimum safe working temperature at the vessel's maximum design pressure. It is based on the steel used in the vessel, the wall thickness, and knowledge of the vessel's manufacture including the type of welding, heat treatment and material tests undertaken by the manufacturer. This work was expected to confirm that all GP1 vessels which were to be put back into service were suitable for the temperatures to which they were to be exposed. Where necessary, low temperature protective devices would be provided and appropriately calibrated.

### ***OPERATIONS, TRAINING AND STAFFING***

- 9.84 Because of the changes made to GP1, it has been necessary to prepare new written operating procedures and to update the Longford Operating Procedures Manual. In addition, the critical operating parameters documented in that manual have been updated to reflect process changes and actions to be taken to prevent critical parameters being exceeded.

9.85 Operating training modules have also been developed for all the changes and special training is being provided to all operating personnel prior to their being required to operate the revised GP1 facilities.

9.86 Additional staff have been provided to support the normal operating staff of GP1 during commissioning and start-up of the revised facilities. In addition, start-up and commissioning engineers have been available on site to ensure full understanding of the revised processes.

### ENHANCEMENT OF CAPACITY AND FLEXIBILITY OF GP2 AND GP3

9.87 As the sales gas produced by GP2 and GP3 is well within the quality specification limits, Esso has decided to install additional treating equipment and bypass lines within those two plants to allow the use of treated or partly processed gas to supplement sales gas output during times of operating difficulty in the gas plant.

9.88 This de-bottlenecking of capacity is illustrated in Figure 9.4 which shows the additional facilities required and the expected output in thousands of cubic metres per day (km<sup>3</sup>/d). GP2 is being fitted with a larger filter separator, a larger dust filter and a larger rich gas bypass together with a new cold gas bypass. GP3 is receiving the filter separator and dust separator removed from GP2 which will be installed in parallel with the existing units. Two additional molecular sieves and a new cold gas bypass are being added.

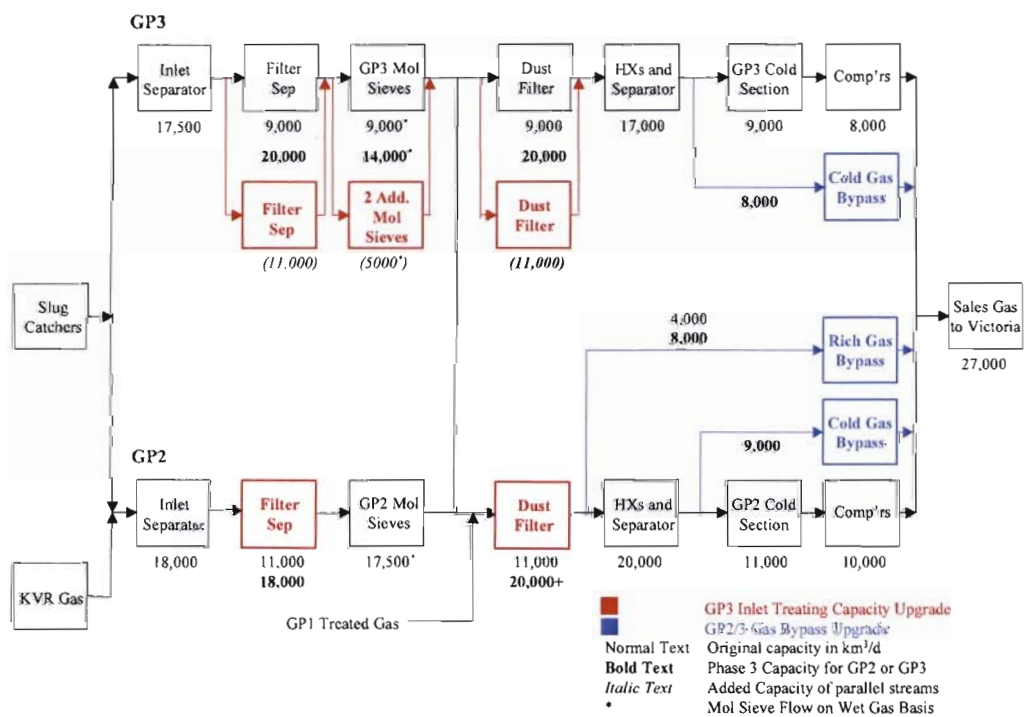


Figure 9.4 De-bottlenecking block diagram

- 9.89 The rich gas bypass in GP2 feeds gas from the molecular sieves into the sales gas stream. As this gas has not been cooled, it will still contain its heavy components and therefore will have a high heating value and Wobbe Index number. This restricts the amount that can be added to the sales gas without exceeding the sales gas specification.
- 9.90 Each of the cold gas bypasses takes gas downstream from the heat exchangers and separators in each plant and feeds it into the sales gas stream. As this gas will have been cooled to around -30°C, some of the propane and most of the butane will have been removed and it will have a lower heating value and Wobbe Index number than rich gas. Consequently, a larger proportion of cold gas can be mixed into the sales gas stream than when rich gas is being bypassed.
- 9.91 The combined output of GP2 and GP3, with maximum allowable bypassing of cold gas to produce gas within specified limits, is estimated at 27000 km<sup>3</sup>/d or 27 Mm<sup>3</sup>/d. This is more than required to meet Gascor's and other users' maximum demand quantity (MDQ) of 1007 TJ which amounts to only about 25.1 Mm<sup>3</sup>/d at a heating value of 40.1 MJ/m<sup>3</sup>. The limitation on throughput is generally imposed by the Wobbe Index of the sales gas, but the allowable temperature of -2°C for the mixture of gases entering the sales gas pipeline may also become a limitation.
- 9.92 HAZOP studies have been conducted for the GP2 and GP3 bypasses and the additional molecular sieves for GP3. These studies confirmed that the proposed additions and modifications were feasible options and will provide a safe means of gaining peak capacity from GP2 and GP3 to meet contingencies.
- 9.93 The HAZOP studies have been supplemented by a review of Critical Operating Parameters (COPs) for GP2 and GP3. These are to ensure that there are clear and appropriate corrective actions to be taken if operating parameter alarms are triggered. Where no control or automatic shutdown exists to protect the plant from conditions outside the specified limits, corrective action by operators is laid down and operator training programs have been instituted to ensure an effective response.
- 9.94 The reliability of GP2 and GP3 has also been enhanced by increasing stock levels of spare equipment for those plants and pre-testing spare control cards for the GP3 Solar Mars sales gas compressors to facilitate rapid changeovers in the event of card failure. In addition, an air compressor has been installed to back up the existing compressors supplying instrument air.

## ***CAPACITY OF RESTORED PLANT***

- 9.95 As indicated above, GP2 and GP3 can meet the winter peak under emergency conditions without GP1 in operation, provided the planned modifications are completed without delay.
- 9.96 With GP1 restarted as a cold separation plant and all hydrocarbon liquid stabilising facilities operating, the Longford Plant is estimated to have a maximum output of 29 Mm<sup>3</sup>/d. This is made up as follows:

***Table 9.2 Longford plant capacity***

Process Section	Capacity (Mm <sup>3</sup> /d)
GP1 cold separation	8
GP2 process capacity	10
GP3 process capacity	8
GP2 and GP3 cold bypass	3
Total	29

- 9.97 On most days in winter, with all three plants operational, the cold bypass will not be needed as the normal processing capacity of 26 Mm<sup>3</sup>/d will be sufficient to meet the MDQ of 25.1 Mm<sup>3</sup>/d.
- 9.98 As the complexity of GP1 has been reduced by leaving the lean oil system out of service, and with the modifications made to the condensate handling and stabilisation system, availability and operability should be improved in comparison with its pre-accident condition.

## ***FUTURE PROPOSALS***

- 9.99 Esso has appointed a Long Term Gas Projects supervisor to study potential upstream production enhancement, and is giving consideration to stand-alone gas supply alternatives. These long term projects are outside the Terms of Reference of this Commission, but the proposed study of means to enhance ethane recovery in GP1, GP2 and GP3 does fall within the Commission's scope. This matter is dealt with in Chapter 10.

# Chapter 10

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## THE SUPPLY OF ETHANE TO THE PETROCHEMICAL INDUSTRY

- 10.1 The restart of GP1 as a cold separation plant without the use of lean oil absorption will limit the production of ethane from the Longford plant. As stated in paragraph 9.53 the demand for ethane at the time of the Longford accident was 650 tonnes per day, but production from the restarted plant is not expected to exceed 550 tonnes per day in mid-winter and will fall to about 300 tonnes per day in mid-summer in line with the reduced gas demand. This was a matter of concern to the two customers for ethane: Huntsman Chemical Company Australia Pty Ltd (Huntsman) situated at Footscray and Kemcor Olefins Pty Ltd and its affiliates (Kemcor) situated at Altona. Esso has appointed a long term gas project team which has, as one of its tasks, a study of the means to enhance ethane recovery at Longford. However, at the time of preparation of this report, the Commission is not aware of any proposals to achieve this objective.
- 10.2 Huntsman and Kemcor lost their supply of natural gas and ethane on 25 September 1998. Kemcor also lost the supply of heavy gas oil which it used as another feed stock. This was supplied by Mobil Refining Aust. Pty Ltd from its Altona Refinery, but the oil was from Bass Strait and was initially processed through the Longford plant. Supplies of gas and a limited supply of ethane were restored on 5 October 1998, but the supply of heavy gas oil did not resume until early December.
- 10.3 The ethane, which was the major feedstock for both companies, was first converted to ethylene in a steam cracker, ethylene being the building block for many other petrochemicals. In the case of Huntsman, the ethylene was converted to styrene monomer. This in turn was converted to polystyrene and other plastics, resins and gels. Some of this styrene monomer was sold to other Australian manufacturers who converted it into a multiplicity of plastics, resins and synthetic rubber compounds. Huntsman was, and is, the sole manufacturer of styrene monomer in Australia.
- 10.4 The ethylene production process also produced some propylene and butadiene which was used by Kemcor to make polypropylene and synthetic rubber respectively. Some of the ethylene stream was converted to high density polyethylene (polythene) of which Kemcor was the sole Australian manufacturer, supplying 75% of the Australian market for that

product in 1997. High density polythene is used to produce plastic containers, pipes, sheeting and moulded products.

- 10.5 Another portion of the ethylene stream was converted to low density polythene. This material is used to make such items as plastic bags, soft moulded products, insulation for electric cables and shrink wrap. In 1997, Kemcor's share of the Australian market for low density polythene was 21%. As another Australian supplier provided 56% of the Australian market, it would be necessary to import 44% of Australia's needs if Kemcor were unable to continue supply.
- 10.6 Kemcor's share of the 1997 Australian market for polypropylene and synthetic rubber was 15% and 97% respectively. Polypropylene is primarily used for making rigid plastic products while synthetic rubber is used almost exclusively for manufacture of tyres.
- 10.7 These statistics indicate the importance of Huntsman and Kemcor as major Australian producers of petrochemicals based on ethane as a feedstock. Their significance in the Australian economy can be gauged from the plastics and chemical industry's contribution to Australia's Gross Domestic Product (GDP) of \$7.8 billion which was 1½% of the Australian GDP for 1996/7. Approximately \$3 billion of this GDP is attributable to the plastics and chemical industry in Victoria.
- 10.8 There has been a rapid rise in the importation of plastics and chemicals to Australia. The value of these imports has risen from \$6.4 billion in 1990 to \$12.8 billion in 1998. This 100% increase over 8 years has been partially offset by an increase in the value of exports of plastics and chemicals from \$1.6 billion in 1990 to \$3.8 billion in 1998.
- 10.9 Kemcor employs some 900 people, with another 300 providing services under contract. Huntsman employs 450 people, with another 500 providing services to it. A number of the customers of Kemcor and Huntsman are reliant on raw materials and semi-finished products from these producers. These cannot be readily replaced by imports. As a result of the reduced ethane production at Longford these downstream manufacturing facilities are likely to be adversely affected. Should that occur, the importation of finished products would become necessary to replace those previously manufactured in Australia. The likely reduction in employment in those events is evident.
- 10.10 Ethane is a bulk commodity which is not widely traded internationally. Almost all ethane used as petrochemical feed stock is delivered by pipeline from the producer to the user's plant where little if any storage facilities are provided. This is because liquid ethane can only be stored at a relatively high pressure if at atmospheric temperature (about 5,600 kPa at

20°C) or at -88°C if at atmospheric pressure. The prospect of an alternative supply of ethane to the Victorian manufacturers is therefore unlikely as it requires not only a different source of ethane but also a new and expensive pipeline to deliver it.

- 10.11 The Commission is of the view that Esso should strengthen its endeavours to find an economical means of restoring the supply of ethane to its pre-September 1998 level in order to ensure the viability of an important industry.





# Chapter 11

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## THE HYDRATE INCIDENT

### *SCOPE*

- 11.1 In June 1998, hydrates formed in the slugcatchers which feed hydrocarbons to all three gas plants. As a consequence, Esso was not able to meet gas demands placed by VENCORP on 10, 11 or 14 June 1998. The Commission has examined this incident as part of its obligation to investigate and report upon whether the hydrate incident was a contributing factor to the occurrence of the explosion, fire and failure of gas supply on 25 September 1998. As will appear below, the Commission is of the view that the hydrate incident did not contribute to the events which occurred on 25 September 1998. It has also examined the hydrate incident as part of its obligation to consider what steps should be taken by Esso or BHP to prevent or lessen the risk of a further disruption of gas supply from the Longford facilities, whatever the cause.

### *HYDRATE FORMATION AND PREVENTION*

- 11.2 The conditions giving rise to the formation of hydrates are well understood within the oil and gas industry. Hydrates are solids with ice-like characteristics. They form under conditions of low temperatures and high pressure when light hydrocarbon molecules are in the presence of water.
- 11.3 The potential for hydrates to affect production operations was well known to Esso. Following the commencement of gas production at Longford in 1969, Esso used methanol to inhibit hydrate formation. In 1979 Esso adopted, and has maintained, the practice of injecting glycol into the offshore pipelines in preference to methanol as a means of preventing hydrates from forming. In 1982, an Esso employee, Peter Symes, presented a paper to a conference on the benefits Esso achieved by changing from the injection of methanol to monoethylene glycol, to inhibit hydrate formation. This paper was later published in the proceedings of the conference.
- 11.4 Glycol is the same component as is contained in the anti-freeze solution used in a car radiator. After injection offshore, a solution of water and glycol is recovered at the Longford slugcatchers, concentrated to restore glycol content to at least 90% and sent by

truck to Esso's Barry's Beach marine terminal from which it is shipped to the main gas production platforms to be used again.

- 11.5 Storage facilities on the platforms ensure there are sufficient supplies of glycol to withstand the failure of deliveries due to bad weather or for other reasons. In an emergency, supplies can be flown out to the platforms by helicopters. The pumps used to inject the glycol into the gas streams are electrical and there are stand-by facilities. The glycol metering facilities and injection controls are designed to fail safe, that is, to fail in a position allowing a maximum injection of glycol.
- 11.6 The rate at which glycol is injected into the gas streams is established from computer spreadsheet tables based upon the pressure of the gas and liquid in the separators on the platforms. A separator is a vessel designed to separate the liquid from the gas. Also taken into account in the calculation is the "cold point" temperature and the assumed pressure in the slugcatchers. The cold point temperature is the lowest temperature in the pipeline between the platform and Longford. It changes position seasonally, principally because there is a variation in sea temperature and gas rates, the latter resulting in loss of pressure which in turn results in a lower temperature in the pipeline. The cold point temperature is generally at the slugcatchers' inlet during winter and at Site 1, which is essentially the landfall point of the Marlin gas pipeline, during summer.
- 11.7 The rate of injection of glycol is expressed in terms of the litres of glycol to be injected per 1000 cubic metres of gas leaving the platform. The ratio is calculated by the platform operators every four hours, based upon the process conditions, and is entered into the Bailey control system. That control system then alters the rate of glycol injection according to the set ratio as the gas production varies. The Bailey system calculates the cumulative glycol and gas flow ratio over specific time intervals. This allows the operators to check and validate the measured amount of glycol injected, against the depletion of glycol in the storage tanks.
- 11.8 Other means to prevent the formation of hydrates are to remove the presence of water and its vapour from the gas streams, to raise the temperature of the gas or to lower the operating pressures of the gas system. The latter is impractical in a gas production system that is required to operate under pressure. Each of the offshore platforms is fitted with separators designed to remove the water from the gas streams prior to the gas entering the pipelines to the shore. However, since 1995, Esso operated the Barracouta platform separator in "flooded mode". Operating a separator in a flooded mode means that the liquid off-take

valves on the separators are shut and all well fluids, condensate, water and gas leave the separator via the gas pipeline to Longford. This defeats the design intent of the separator.

### ***CHRONOLOGY OF THE INCIDENT***

- 11.9 On 31 May 1998, a compressor on the Snapper platform developed an oil seal problem. As a result, a decision was taken by Esso to run the Snapper platform with no vapour/liquid separation and to direct all liquids to the gas pipeline. Three wells connected to the Snapper platform have the capacity to produce large amounts of water. They are known as HI-GOR wells. Two of these wells were known by Esso to be able to produce about seven times the amount of water that was used as the basis of the calculation for the glycol required. That did not matter when the platform was operated with the separator working normally, but with the platform operating in a flooded mode all of this additional water would have entered the gas pipeline, requiring the injection of additional glycol. On 3 and 4 June one of the HI-GOR wells on the Snapper platform which had a higher yield of water, was in production for most of the day.
- 11.10 Immediately before the Queen's birthday long weekend nominations for gas from Longford peaked at around 20 Mm<sup>3</sup>/d. On Saturday, 6 June 1998, the first day of the long holiday weekend the demand for sales gas from both industrial and residential customers dropped to approximately 16 Mm<sup>3</sup>/d. With the start-up of industry at the end of that weekend on Tuesday, 9 June, and with residential consumers responding to cold ambient air temperatures which reached as low as 3°C, the demand for sales gas increased to approximately 21 Mm<sup>3</sup>/d.
- 11.11 In addition, on Tuesday 9 June, Kemcor advised Esso that, because of an unscheduled shutdown in its plant, its ethane requirement would be reduced. This resulted in a reduction of the total Bass Strait ethane requirement by 55%. With the decreased demand for ethane, Esso decided to switch 5.0 Mm<sup>3</sup>/d of production from Marlin to the Snapper platform. Also on 9 June, the Barracouta platform, which was not manned, was shut in because of the activation of a safety alarm. As the platform was unmanned, it could not be restarted and brought back into production until the following morning. Esso then decided to increase the production from Snapper by another 5.0 Mm<sup>3</sup>/d. This meant increasing the production from the HI-GOR wells known to produce substantial amounts of water. Despite these changes to its production profile, Esso did not review the amount of glycol that should be injected to account for increased water.
- 11.12 In addition to the changes in the production profile of the wells, the increased demand for gas from the Snapper platform substantially increased the flow rates through the offshore

pipelines. This meant any liquids (whether water or condensate) that had settled out in the offshore pipelines during the period of low flows were 'swept' through to the Longford slugcatchers with the higher gas flow rates.

- 11.13 On Wednesday, 10 June, nominations for sales gas were again high at approximately 21Mm<sup>3</sup>/d. At about 8.50 am on that day, the Barracouta Slugcatcher's liquid separator barrels blocked suddenly. While the blockage allowed for a continued flow of gas through the slugcatchers to the gas plants themselves, the blockage restricted the separation of liquids from the gas. As a result, liquids from the slugcatchers carried over into GP2 and GP3 inlet separators, causing them to shut down. After a period, the two plants were successfully restarted. Methanol, which is used to clear hydrates, was injected into the slugcatcher barrels and arrangements were made to radiograph the barrels to identify the extent of the problem. The radiographs indicated a hydrate blockage in the Barracouta slugcatcher. It was taken out of service and depressured in an attempt to dissociate the hydrates. In addition, warm condensate was re-routed from the Marlin Slugcatcher into the Barracouta Slugcatcher. High-current, industrial heating blankets, powered by portable generators, were also applied to the barrels to provide warming as a further means of removing the hydrates. VENCORP and Gascor were formally notified by Esso that the request for gas supplies could not be met. At about 6.00 pm on 10 June, VENCORP began vaporising liquefied natural gas stored at Dandenong to ensure that the gas pressure in the distribution system was adequate for the following day's peak demand period.
- 11.14 During the early morning of 11 June, liquids from the Marlin slugcatchers carried over into GP2 and GP3, again causing shutdowns. Initially Esso thought that the carryover was caused by the high liquid rates in the offshore pipelines being fed into a single slugcatcher. However, a hydrate formation was later found to be a contributing factor. Gas sales were reduced to the maximum sustainable for continuous operation while methanol was injected into the slugcatcher and heat blankets were put in place.
- 11.15 During the early morning of 11 June, VENCORP notified major industrial consumers that it was beginning to curtail gas supply to them. It also appealed to residential consumers to reduce their usage of gas voluntarily. Esso was able to meet the requests for gas within these constraints on 12 and 13 June.
- 11.16 On 14 June, during operations to sweep liquids from the pipeline system the Marlin slugcatcher blocked suddenly, again restricting the throughput of gas. This led to an under-delivery of the gas requested from Esso on 14 June while the blockage was cleared. It was

cleared quickly later that same day, allowing delivery of the full gas request on Monday, 15 June 1998.

### ***ESSO'S INTERNAL INVESTIGATION***

11.17 Esso itself undertook a comprehensive investigation of the hydrate incident. It concluded that a number of factors which were present before or during the incident gave rise to conditions severe enough to cause the formation of the hydrates which blocked the slugcatchers. These were:

- large increase in gas demand due to a public holiday long weekend followed by significantly colder weather;
- changing gas production demands on individual facilities due to an ethane customer's unplanned shutdown and the safety system shutdown of a remotely operated platform;
- significant increases in individual pipeline flowrates due to gas facility production demand changes, causing liquids lying in the pipelines to be swept from the pipelines into the slugcatchers;
- changes in offshore well producing characteristics and facility configurations (arising from unplanned facility shutdowns) that may have allowed some under-inhibited liquids to enter the gas system;
- waxy crude oil in the system possibly providing stable structures for hydrates to form and subsequently hindering dissociation; and
- the high pipeline rate required to maintain gas supply following the initial blockage of one slugcatcher that resulted in a lower onshore pipeline temperature.

11.18 The item "changes in offshore well producing characteristics and facility configurations" appears to be an oblique reference to the fact that the Barracouta platform's separators were operated in a flooded mode since 1995 and the Snapper platform's separators had to be operated in a flooded mode between 30 May 1998 and 15 June 1998 due to the compressor seal failure.

11.19 Figure 2.3 is a diagram showing the gas pipelines and Longford slugcatchers.

## ***OBSERVATIONS ON ESSO'S HYDRATE REPORT***

- 11.20 In its investigation, Esso stressed the conservative nature of its calculations with respect to the injection of glycol. This, it said, was to be seen in,
- the adoption of dissociation temperature for the hydrates as the cold point temperature rather than temperature of formation, because the latter may be lower;
  - a 1.7°C 'safety margin' built into the base calculation;
  - the selection of the most conservative platform separator or slugcatcher variables where possible;
  - the rounding down of glycol concentration to the nearest 5% increment.
- 11.21 However, the difference between dissociation temperature and formation temperature of a hydrate is inherently unpredictable so that the actual degree of conservatism adopted by Esso cannot be established with any precision. Further, it is more accurate to describe the 1.7°C factor as a means to compensate for inaccuracies in the mathematical models rather than as a 'safety margin'.
- 11.22 Moreover, conservatism in the calculation of the required injection of glycol can be offset by a number of variable factors. The most important of these is the time during which the pipeline liquids, both condensate and water, settle out and remain in the low points of the pipeline. The period of time these liquids remain in the pipes is longest in summer when gas flow rates are low and shortest in winter when gas flow rates are high. In addition, water being more dense than condensate, tends to gravitate to the bottom of any such pools of liquid taking longer for it to traverse the system. The imperfect mixing of held-up water and incoming water means that water within a pool will generally have been in the system for far longer than any modelling would indicate. Field tests in winter 1998 indicated that a spike in glycol injection took four days to appear at Longford. Water may take days or even weeks to traverse the pipeline system when gas flow rates are low.
- 11.23 The result is that the Cold Point temperatures used to calculate the required rate of injection of glycol when the gas and water leave the platform may have changed at the time the water enters the slugcatchers. This is a systemic error, which will be non-conservative at the transition from summer to winter as ambient and sea temperatures fall and gas flow rates increase leading to a drop in the Cold Point temperature.

- 11.24 The major non-systemic factor offsetting the conservatism of the basic calculation for glycol injection is the departure from normal operations on the platforms. Esso's calculations assumed that the amount of water vapour leaving a platform was at equilibrium condition for the temperature and pressure of the separators.
- 11.25 On the Barracouta and Marlin platforms there was an oil pipeline as well as a gas pipeline. Liquid separated from the gas by the separator was sent to Longford in the oil pipeline. When the oil system was shut down, as happened on the Barracouta and Marlin platforms, the water was sent to Longford in the gas pipeline. It could not be dumped at sea for environmental reasons. The valve on the separator which put the water into the oil system was shut and the separator operated in a flooded mode in order to maintain gas production. Under those conditions, the amount of water remaining in the gas was likely to be twice that assumed when calculating the amount of glycol required.
- 11.26 Esso also noted that there was a further degree of conservatism in the actual operation of the system. The Esso platform operators appear to have routinely injected more glycol than required by the calculations. That practice was neither encouraged nor discouraged by Esso. The level of over-injection may have been sufficient to offset the effect of operation in flooded mode in otherwise normal conditions, e.g. stable gas demands and few changes in well characteristics.
- 11.27 Because production from the Marlin platform was minimised on 9 June, there was no significant injection of glycol from that platform to compensate for the additional water in the gas stream from the Snapper platform. Also, the high rates of gas flow in the Snapper pipeline system would have increased the rate at which any under-inhibited water, leading to a potential hydrate, would have been swept through the system into the slugcatchers.
- 11.28 Thus, significant quantities of under-inhibited water entered the gas pipeline systems from the Barracouta and Snapper platforms which were not included in the calculation of the glycol required to be injected. The Barracouta water entered the system due to the flooded mode of operation of the separators and could have counteracted most of the buffer effect of the regular over-injection of glycol by operators. From past experience, it would seem that this might not, of itself, have been sufficient to generate the hydrate problem on 10 June 1998. However the flooded mode of operation of the Snapper platform meant that all liquids produced entered the pipeline for about ten days before the incident on 10 June, including the potentially substantial amount of aquifer water arising from the operation of some HI-GOR wells during that period. This produced a large deficit in the amount of glycol required to inhibit the formation of hydrates.



- 11.29 The time taken for liquids to emerge from the pipeline system and the colder temperatures of the gas near the slugcatchers, were also factors contributing to the likelihood of the occurrence of hydrates. The increase in the Snapper gas flow rates would have had a sweeping effect upon the water in the Snapper pipeline system. The combination of these factors resulted in water passing through the system that was not sufficiently inhibited to prevent the formation of hydrates. These hydrates commenced to form and stabilise into a solid mass, initially at the inlet end of the Barracouta slugcatcher. The hydrate blockage in the Marlin slugcatcher was an extension of the same problem, arising from further significant drops in temperature as flows and conditions changed during the incident.

### ***CORRECTIVE MEASURES TAKEN BY ESSO***

- 11.30 As a result of its investigation of this incident, Esso developed a package of corrective actions, which it called its Gas Management System, to prevent recurrence. A fixed target ratio of glycol to gas flowrate has now been adopted for each platform, using a fixed and conservative basis for the calculation of the required amount of glycol. The cold point temperature adopted is now 6°C which compares with cold point temperatures measured at the time of the incident of 10°C to 11°C. These ratios are two to three times the target ratios that would have applied at the time of the incident. The achievement of these ratios will represent a considerable increase in the level of conservatism applied in the injection of glycol. The new ratios have applied since the incident on 10 June 1998.
- 11.31 Esso proposes to give increased attention to ascertaining any discrepancy between the actual rate of glycol injection and the target rate and to report the results more widely. There is to be a continued emphasis on ascertaining the metered rate of glycol injection and the changes in tank inventory. All glycol injection on the platforms is to be measured by new coriolis meters for improved accuracy and reliability. Esso proposes to increase its checks for glycol impurity or degradation by additional platform measures, monitoring the regeneration plant and analysing regeneration plant feed, plant product and glycol supply to the platforms. Standards have been set and the action to be taken defined in the case of deviation from the standards. Further, glycol inventory management on the platforms has been strengthened and some additional glycol storage capacity is to be commissioned. A procedure has been formalised for the supply of glycol to the platforms in emergencies. Finally, Esso proposes to carry out additional monitoring of glycol in the water from the slugcatchers to forewarn of possible problems.
- 11.32 The Barracouta platform, which was not staffed before the hydrate incident, is now manned and regular attention is given to the levels of separator liquids. The platform is to remain

staffed until reliable management of those liquids can be ensured as a remote operation from the Snapper platform. The objective is that there be no regular entry of separator water into the gas pipeline.

- 11.33 Additional facilities are being installed on the Snapper platform so that liquids from the separators will have an outlet path other than to the gas pipeline. It will be possible to direct condensate and water to the oil pipeline even during maintenance activity, such as required the separators to be run in flooded mode in the period before the hydrate incident.
- 11.34 An operating policy has been adopted precluding the flooded operation of offshore separators. Any deviation from this policy will be treated as a change in management process and will require specified procedures to be adopted. Any additional entry of water to the gas pipeline systems will require specific additional injection of glycol and, where necessary, wells in the Snapper Field producing high liquid levels will be shut in.
- 11.35 These measures, together with improved training, line pigging and sweeping facilities, should minimise the risk of a repetition of a hydrate incident of the severity of that was experienced on 10 June 1998.

### ***OBSERVATIONS***

- 11.36 The Commission has concluded that the hydrate incident on 10 June, 1998 did not contribute to the explosion and fire on 25 September 1998. The physical connection between the two incidents is tenuous. A physical connection that was drawn between the two events concerned the presence of molecular sieve dust found in GP903B when it was opened for inspection after the incident on 25 September. As noted in Symes' 1982 paper, the compound used in the molecular sieves, or dehydrators, is damaged by contact with methanol, large quantities of which were injected into the slugcatchers during the hydrate incident. It would have entered the dehydrators as methanol vapour leading to a possible breakdown of the molecular sieve particles and an accumulation of molecular sieve dust in GP903. However, it is also known that the action of methanol on the molecular sieve compound is to leave a carbon residue in the lattice structure during regeneration of the sieve, thereby reducing its absorption capacity but not causing physical breakdown.
- 11.37 Be that as it may, the accumulation of sieve dust in GP903 was not sufficient to prevent that exchanger from performing its condensate heating function on the morning of 25 September 1998. That can be seen from the rapid response to the opening of the TRC3B bypass valve at 8.22 am. This adjustment caused the condensate temperature to rise about 12°C in 28 minutes with an initial rise of 5°C in the first 5 minutes.

There are, however, a number of similarities or parallels between the deficiencies in Esso's management systems that contributed to the hydrate incident occurring of 10 June and those which contributed to the accident on 25 September.

- Most notable is that the potential for the formation of hydrates was well known to Esso prior to the June incident just as the potential for cold temperatures to develop upon the loss of lean oil was known prior to the September accident. As a part of Esso's own investigation of the hydrate incident, it performed a review of control room logbooks dating back to 1993 and PIDAS information dating back to 1994. Those reviews identified a number of previous hydrate incidents, some of which resulted in significant hydrate formations in the slugcatcher area. As part of its corrective actions, Esso has now developed a series of operating practices, one of which addresses the rate at which gas flows from the platforms should be increased to minimise sweeping large amounts of liquids from the offshore pipelines into the slugcatchers. Whilst one of Esso's own engineers had published a paper in 1978 on just this subject, that knowledge was apparently lost over time and was not reflected in its operating procedures and practices current in June 1998.
- The lack of a spare parts for the compressor on the Snapper platform meant operating in an abnormal state (flooded) for a period of at least ten days before the incident without developing and implementing temporary preventive measures. As indicated in Esso's management system, such corrective measures could have taken the form of operating instructions or revisions to the glycol injection rates. This approach was similar to that taken with the TRC3B valve, which was out of service for upwards of two weeks without temporary measures being implemented to address the problem.
- As part of its investigative and corrective process, Esso developed a number of risk scenarios analysing the potential for hydrates to form and the consequences that could arise should they form. No such scenarios were included in previous periodic risk assessments undertaken by Esso. As discussed in Chapter 13, the same deficiency existed in relation to cold temperature incidents occurring in GP1. No PRA scenario for GP1 ever addressed this issue.

# Chapter 12

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## THE COLD TEMPERATURE INCIDENT

- 12.1 On 28 August 1998, an incident occurred in GP1, which should have given warning of the consequences of operating the plant without lean oil circulation to the absorbers.

### *THE EVENT*

- 12.2 Some weeks before 28 August 1998, GP1202A, which was one of the two pumps delivering lean oil from the Oil Saturator Tank, had been taken out of service for the fitting of new mechanical seals. That left GP1202B operating without a spare pump. On the morning of 28 August 1998, GP1202B developed a leak from one of its seals and a decision was made to shut it down and replace the seal on site. The GP1 supervisor and operators (Wijgers, Olsson and Hutty) met and discussed the steps to be taken to make the plant safe for the repair of the pump. This necessitated the shut down of the lean oil system. The KVR gas from the CSP was diverted to GP2, leaving only the inlet gas from offshore to flow to GP1. The total flow of offshore gas was reduced to 3 Mm<sup>3</sup>/day. GP1202B was then stopped, although the GP1201 pumps pumping lean oil to the Oil Saturator Tank were left running. It may have been expected that the level control valve LRC2 would have reduced lean oil flow sufficiently to activate LFSD8 and thereby shut down the GP1201 pumps. This did not occur because LRC2 did not achieve a tight shut off and the level in the Oil Saturator Tank continued to rise. The GP1201 pumps were therefore manually shut down. The GP1204 pumps and the GP501 heaters were left online to facilitate a start up once GP1202B had been repaired. The LC8A and B valves were closed to stop the flow of fluid from the rich oil trays in the Absorbers to the Rich Oil Flash Tank.
- 12.3 The replacement of the faulty seal on GP1202B commenced at about 9.45 am and was completed at about 3.30 pm. Wijgers, the shift supervisor, then returned to the ROD/ROF area to supervise the re-start of the lean oil system. At about this time, a leak from GP922 was noticed. Wijgers could not recall whether the leak was from GP905 or GP922, but the presence of a drip tray still under GP922 on 25 September 1998 and the recollection of the area operator, Olsson, confirm that the leaking vessel was GP922.
- 12.4 Wijgers also noticed that the pipes between the ROD and GP922 and GP905 were coated with ice and that the western end of GP905 also had a frosty appearance. Olsson recalls that

the warm feed line from GP904 to the ROD was coated with ice, but he did not notice any ice on the pipework in the area of GP922 and GP905.

- 12.5 The re-start of the GP1202 and the GP1201 pumps was carried out without incident and, as normal temperatures were restored, the ice melted. The gas flow through the absorbers was increased and the KVR gas was returned to GP1.
- 12.6 One puzzling aspect of the train of events is that, although the temperature recorded by TRC4, which controls the temperature at the bottom of the ROD, initially fell from about 100°C to about 80°C, “hours later” it was found by Hutty, the control room operator, to have risen to 160°C and to be “holding steady”.

### ***OBSERVATIONS***

- 12.7 The most likely explanation for the coldness that was seen in the pipework is the leakage of condensate through the valve FRC7 having the same effect as on 25 September. As stated in the description of the 25 September accident, the evidence is that FRC7 leaked about 90 kl/day when shut. Additionally, there would have been the flow and expansion of gas through the two rich oil level control valves, LC8A and LC8B, on the absorbers. The operators said they fully closed the LC8 valves. Nevertheless the valves are likely to have permitted a small leakage as there was a large pressure difference of 3,300 kPa between the absorbers and the Rich Oil Flash Tank. Control valves typically do not shut off tightly. To prevent gas passing through LC8A and LC8B and dropping in temperature as it expanded, the *1975 Operating Instructions for Absorption-Oil System* recommended that the manual block valves to the control valves be closed when the lean oil flow had ceased and could not be restored quickly. The reduction in temperature of gas as it expands is known as the Joule-Thompson effect.
- 12.8 The temperature of the gas as it left the absorbers would have been about -30°C and the drop in temperature by reason of the Joule-Thompson effect would have been in the order of 13°C. The temperature of the gas entering the Rich Oil Flash Tank would, therefore, have been about -43°C, only marginally above the design limit of -46°C for the Rich Oil Flash Tank. The temperature of the condensate flowing through FRC7 would have depended on its composition and initial temperature. A typical condensate, devoid of heavy KVR components, would have flashed to -42°C on its way to the Rich Oil Flash Tank, as shown by simulation analysis.
- 12.9 The very cold gas in the Rich Oil Flash Tank would have been discharged through pressure control valve PRC4 to the KVR compressors unless the flow of condensate was insufficient

to cover the bottom of the tank. In that event, gas and liquid would have been able to enter the pipes feeding the ROD through the series of heat exchangers. One of those heat exchangers was GP924 and the flow through it was controlled by FRC9 at about 6.5 litres/second. However, it is possible that the LTSD1 valve closed, limiting the flow to the extent that it achieved a tight shut off. The other heat exchangers were GP930, GP925 and GP904. The flow through these heat exchangers was controlled by control valve LRC1, which was likely to pass a significant, but unknown, volume of liquid or gas or both, even in the closed position. The ice seen on the line from the GP904 exchanger to the ROD shows that the fluid in the line was cold.

- 12.10 The only flow of liquids into the Rich Oil Flash Tank would have been the leakage through FRC7 of 90 kl/d (1.04 l/s) before it flashed, with a consequent liquid flow reduction to less than 1 litre per second. The Rich Oil Flash Tank would therefore have emptied itself by discharging its contents of about 8,100 litres into the ROD in less than half an hour unless the low temperature shut down switch, LTSD1, on the cold feed to the ROD was activated.
- 12.11 After the Rich Oil Flash Tank was empty, a mixed stream of cold gas and condensate would have passed through the heat exchangers and entered the ROD. This stream would have cooled as it flashed and expanded from some 3,500 kPa in the Rich Oil Flash Tank to about 2,800 kPa in the ROD. The volume of liquid flowing to the ROD would have been reduced to significantly less than one litre per second and its temperature in the absence of any heating in the heat exchangers would theoretically have fallen to around -48°C. However, in view of the very low flow rates and the large thermal mass of the system through which the condensate would have been flowing, it is most unlikely that temperatures of that order would have been reached in the bottom of the ROD.
- 12.12 The very small stream of liquid entering the ROD would have been directed into the tube side of GP905 while the seal flushing flow for the GP1204 pumps would have been circulating on the shell side. During the seal flushing process, the lean oil would have passed through the seals and joined the mainstream of lean oil being pumped by the GP1204 pumps. These pumps would have sent that lean oil back to GP905 where it would have constituted the only flow of lean oil, as the GP1201 pumps had stopped. The pipework from the ROD to GP905 would have been very cold, but the return line could have been quite warm as the flow of seal flushing oil of about 36 litres/minute at a temperature of about 250°C would pass through the shell side of GP905. This probably accounts for the reported temperature of 160°C recorded by TRC4 late in the incident.

- 12.13 Although the level control valve at the bottom of the ROD, LC10, would have closed because of the cessation of the flow of rich oil into the bottom of the ROD, it would not have provided a tight shut off and would have allowed some liquid to pass from the bottom of the ROD through GP922 on its way to the ROF. When the Rich Oil Flash Tank had been emptied and any remaining liquid in the bottom of the ROD had passed out through this route, it would have been replaced by cold gas. That would account for the ice on the feedline from the ROD to GP922, which was also seen in the accident on 25 September 1998. In GP922, rich oil would normally have flowed through the tube side, but, because of the process described, it would have become mostly, if not all, cold gas. Because of the leakage in the tubes, the lean oil on the shell side (which would have been at a higher pressure than the gas on the tube side) would have forced itself through the broken tubes and joined the gas stream on the way to the ROF. Even if TRC4 was causing lean oil to bypass GP922, the difference in pressures between the tube and the shell side of GP922 would have forced lean oil into GP922 on the shell side through the normal outlet line and, thence into the broken tubes. It will be recalled that the bypassing of GP922 occurred when extra heat in the bottom of the ROD was required. If the temperature on the outlet of GP905 reached 160°C later in the day as suggested, TRC4 would have directed the flow of lean oil (really seal flushing oil) through GP922 again.
- 12.14 Nevertheless, the leak from the flange on the western end of GP922 would have been caused by a similar abnormal temperature gradient as that to which the vessel was subjected during the lean oil shut down on 25 September. But, as there was some flow of hot lean oil through the vessel at all times (which was not the case on 25 September), no ice was seen to form on the western end cover during this incident.
- 12.15 The similarity between this incident and that which occurred on 25 September 1998 is readily apparent. The reason why the loss of lean oil flow did not on this occasion lead to disaster, as it did on 25 September, is probably threefold. First, absorber condensate levels were controlled and the gas flow through GP1, particularly that from the KVR compressors, was reduced before lean oil circulation was shut down. This prevented the carryover of significant quantities of condensate into the rich oil system and minimised the volume of cold liquids available to chill the downstream equipment. Secondly, the GP1204 pumps and the GP501 heaters were left on for the whole period of the shut down. The limited amount of heat that was available by reason of the seal flushing oil circulation through GP905 and the leaks in the tubes in GP922 would have counteracted the small flow of cold fluids through the tube sides of those two vessels. It may well have been that on 28 August neither of those vessels reached a temperature low enough for them to have been vulnerable to cold

embrittlement (i.e. below  $-27^{\circ}\text{C}$ ). Thirdly, because of the orderly shut down, the apparent lack of upset in either the ROD or ROF and the leaving of the Oil Saturator Tank and the lean oil system full, there was no vapour locking of pumps, no icing of pump pipework and no difficulty in re-starting the equipment.







# Chapter 13

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## MANAGEMENT SYSTEMS

### *OIMS*

- 13.1 Following an oil spill from the oil tanker Exxon Valdez in 1989 and against the background of a number of other disasters arising from the hazardous activities of companies other than the Exxon Corporation and its affiliates, Exxon developed a framework for the safe and environmentally sound operation of its various undertakings. The framework was called Operations Integrity Management Framework (OIMF). Within this framework, Exxon Company International (ECI) developed a series of expectations and guidelines (the ECI Guidelines) which included the ECI Upstream OIMS Guidelines (the ECI Upstream Guidelines). The ECI Upstream Guidelines contained eleven primary elements with associated expectations, and a series of guidelines for the achievement of these expectations. ECI intended that its affiliates, including Esso, should develop a management system in which all the expectations outlined in OIMF and contained in the ECI Guidelines, were met.
- 13.2 The eleven elements referred to in the Guidelines were:
- Element 1 – Management leadership, commitment and accountability;
  - Element 2 – Risk assessment and management;
  - Element 3 – Facilities design and construction;
  - Element 4 – Information/documentation;
  - Element 5 – Personnel and training;
  - Element 6 – Operations and maintenance;
  - Element 7 – Management of change;
  - Element 8 – Third party services;
  - Element 9 – Incident investigation and analysis;
  - Element 10 – Community awareness and emergency preparedness;
  - Element 11 – Operations integrity assessment and improvement.

- 13.3 Utilising OIMF and the ECI Guidelines, Esso developed its Operations Integrity Management System (OIMS). This management system was outlined within a manual known as the OIMS Systems Manual and was detailed in a series of supplementary manuals, charts and other “controlled” documents. A controlled document was one subject to regulation by document management guidelines. The OIMS Systems Manual was the centrepiece of OIMS. It set out the scope and objectives of each of the 11 elements and identified each system owner, as well as the manuals and other documents falling within each system or sub-system. The owner of a system was the person responsible and accountable to ensure that the overall system was working and achieving its objectives in an efficient manner.
- 13.4 It would lie outside the scope of this inquiry to attempt any evaluation of the ECI Guidelines as the framework for Esso’s management system. Such an inquiry would invite an excursion into modern management theory as well as a detailed review of the systems’ antecedents. The Terms of Reference confine the Commission to a consideration of Esso’s management systems as a possible cause of the explosion and fire at Longford on 25 September 1998 and the associated failure of gas supply.
- 13.5 The ECI Upstream Guidelines required the development and maintenance of procedures to ensure the safe operation of the facility, to ensure that procedures were accessible to all personnel required to use them, to ensure that deficiencies were identified and improvements made, to deal with the safety of critical equipment, with the temporary defeat of critical equipment and with the transmission of information between shifts. These expectations (and the others contained in Element 6 of the ECI Upstream Guidelines) were reflected in the OIMS Systems Manual. However, in many respects, there were shortcomings in the way in which Esso implemented its OIMS system at Longford and thus, in the way in which it implemented the ECI Upstream Guidelines.

### ***Training***

- 13.6 The ECI Upstream Guidelines called for the careful selection, placement, ongoing assessment and proper training of employees. They also required Esso to maintain a management system which ensured that the necessary levels of individual and collective experience and knowledge were maintained. Further, they required Esso to provide for ongoing refresher training and also to understand and apply the proper protective measures to deal with safety, health and environmental hazards.
- 13.7 The system of training at Longford changed in 1993 from a “supervisor based” format to a “competency based” format. The evidence was that a competency based training

programme required trainees to demonstrate a knowledge of plant operations, to apply acquired skills and to have an appropriate attitude to safety issues in respect of fellow employees, equipment and the environment. It was unnecessary for the Commission to undertake a detailed investigation of Esso's training programme or its particular training techniques. This was because the accident on 25 September itself demonstrated the primary deficiency in Esso's training. That deficiency lay in the failure of its training programmes, however implemented, to impart or refresh the knowledge required to operate GP1 safely in the conditions which existed on the day. This is discussed further below.

13.8 At no relevant time did any programme include training with respect to the hazards associated with the loss of lean oil flow, the hazards associated with the uncontrolled flow of condensate into the rich oil stream from the absorbers, the critical operating temperatures for GP922 and GP905, the circumstances in which brittle fracture might occur or the procedures for the shutdown or start up of GP1.

13.9 Workbooks were maintained by trainees in which they recorded answers to questions forming part of their training and assessment programme. Whilst it is true that question 12 (Q12), forming part of the Technician 1 competency standard, referred to the loss of lean oil flow, the "correct" answer, which was provided, ignored the real hazards associated with such an upset:

Q12 On the loss of the lean oil circulation pumps state what immediate action should be taken.

A12 Investigate and rectify the problem and restart the system. If unable to restart the system consider transferring the gas to other plants and ensure that main gas chillers at optimum operation.

13.10 There was no reference to the existence of the *1975 Operating Instructions for Absorption-Oil System* nor was the relevant information contained in that document, adopted as part of the correct answer. That work, published by Esso in 1975 (referred to in Chapter 12), was known colloquially as "the Red Book." It was not a controlled document.

13.11 The Red Book contained a section headed "Loss of Lean Oil Circulation" and described the circumstances in which a loss of lean oil flow would occur. It stated: "The loss of circulation will cause an immediate and large increase in the WI; it will also cause a severe upset in the ROF and a less severe upset in the ROD". The reference to "WI" is a reference to the Wobbe Index, an index used in maintaining the production of gas in accordance with given specifications. The Red Book contemplated a sudden loss of lean oil flow and

detailed the action to be taken if the loss continued for more than five minutes. That action included reducing gas flow and, in effect, isolating the absorbers.

- 13.12 Upon the failure to restart the GP1201 pumps and restore lean oil circulation, the source of gas to the absorbers should have been shut-in or diverted. With evidence of excessively cold temperatures in the ROD/ROF area, the absorbers should have been isolated, GP922 should have been depressured and the flanges inspected and repaired. GP905 should have been isolated and allowed to thaw. No attempt should have been made to introduce warm oil into an abnormally cold vessel.
- 13.13 The instructions given by the Red Book were in terms directed only to the maintenance of gas production within specification. The hazards associated with the loss of lean oil flow were not mentioned. In any event, the evidence was that the Red Book was not used in order to operate the plant; the procedures contained in it were recognised by operators to be out of date and, insofar as it was employed in training, it was for its process description.
- 13.14 The Red Book was said to be available to operators in GP1, but the only evidence of its availability was that it was located in the training room adjoining the control room. It was not to be found among the operating procedures available in the control room. The evidence was that it was not consulted on 25 September 1998.

### ***Operating Instructions***

- 13.15 The ECI Guidelines provided in Element 6:
- “Operation of facilities within established parameters and regulations is essential. This requires effective procedures, structured inspection and maintenance systems, reliable safety and control facilities and qualified personnel who consistently execute these procedures and practices”.
- 13.16 An example of Esso’s failure to implement OIMS is apparent from the state of the Longford Plant Operating Procedures Manual which contained the operating procedures for GP1 and was located in the GPI control room. It was a controlled document and was identified by the OIMS Systems Manual as part of OIMS. The manual did not comply with the guidelines in critical respects. It did not contain any reference to the loss of lean oil flow and contained no procedures to deal with such an event. Nor did it contain any reference to GP1 shutdown or start up procedures or the safe operating temperatures for GP905 and GP922. There was no mention of the Red Book in OIMS, whether as part of the operating procedures, as a training aid or otherwise.

- 13.17 It is difficult to understand why operating procedures dealing with a lean oil absorption plant did not include any reference to the importance of maintaining lean oil flow in the operation of the plant. Plainly that was something which was fundamental.

### ***Operator Knowledge***

- 13.18 The deficiencies in operator training and operating procedures were reflected in the evidence of what the operators and supervisors actually did on 25 September 1998. The problem in the ROD/ROF area of GP1 which attracted the attention of plant operators and supervisors was a leak in the flanges of GP922. The steps taken around mid-day to restart the lean oil pumps were undertaken in an effort to restore heat in GP922 in order to reduce the temperature differential across the flanges. This was thought to be responsible for the leaks. The collective experience of those present at GP922 on 25 September 1998 was more than 200 years at Longford and yet no one recognised the hazards associated with the plant conditions which culminated in the explosion and fire.
- 13.19 Jim Ward was the GP1 control room operator on the day of the incident. He had been employed by Esso for 18 years with 11 years experience as an operator. He said he did not appreciate the seriousness of a loss of lean oil flow at the time. His understanding was that if the lean oil system did not operate, the plant would produce off-specification gas. His evidence demonstrated a less than adequate understanding of the lean oil absorption process and, in particular, the consequences of process excursions or upsets.
- 13.20 Greg Foster was a recently qualified technician 1 operator on duty in GP1 on the day of the accident. He had had only two years experience at Longford. His training had commenced in 1996. He said he was not taught the temperatures at which relevant equipment was designed to operate. Nor was he made aware of low temperature protection devices or alarms. He said that there was no training to warn of the risk of equipment failure at low temperatures. He had no idea of the consequences of metal becoming brittle.
- 13.21 Ron Rawson was on duty on the day of the accident. He was an area operator with 18 years experience. He said that his concern about the loss of lean oil was in relation to the leak in GP922. He did not appreciate that there might have been a serious risk to equipment or to safety if the heating medium was not restored within a fairly short period of time after it ceased to flow. He was not aware that the cessation of lean oil circulation for more than 10 to 15 minutes was a very serious matter. He thought the only consequence would be that gas would be “off-spec”.

- 13.22 Ian Kennedy was a relief day supervisor on duty on the day of the incident. He had 27 years of experience, first as an operator, then as shift supervisor, maintenance planner and maintenance supervisor. His understanding of the consequence of a loss of lean oil flow was that it “puts your Wobbe index off-spec.” He was not aware of the risk of brittle fracture. He said that he and Shepard were trying to warm up GP922 to see if the gasket was still going to hold. They were acting on the assumption that they had a small flow of lean oil.
- 13.23 Mike Shepard was production co-ordinator, crude and power generation, at Longford with 28 years experience as an operator, supervisor and training co-ordinator. He was on duty on the day of the accident and was asked for assistance between 11.40 am and mid-day on 25 September 1998. The lean oil system was his special interest. He said he was aware that “brittle fracture could easily be had if we didn’t make sure that we didn’t apply thermal shock to those vessels (GP905 and GP922)”. Shepard participated in the restart of the GP1204 and GP1201 pumps at about mid-day. He and others “were trying to get lean oil flow through the 905 and 922 exchangers”. When seeking to manipulate the TRC4 valve he knew that “lean oil may already be progressing through the system”. He said that when he looked at GP905, “I felt that it couldn’t be left as cold as it was”.
- 13.24 Shepard also said, somewhat inconsistently, that he wanted the lean oil to bypass the exchangers. This was, he said, because of his awareness of the risk of brittle fracture and thermal shock. Even so, he made no attempt to stop the GP1204 or GP1201 pumps once operating or to interfere with the attempts to restart the GP1201 pumps.
- 13.25 Had Shepard truly understood the potential danger he would have stopped the GP1204 pumps and cleared the site rather than engage in the steps which he described in evidence. At the very least, he would have ensured that the steps he took to minimise lean oil circulation through the exchangers, were taken before the GP1201 pumps were restarted. Shepard concentrated his attention on the leak from the flanges of GP922 without any real appreciation of the dangers arising from the condition of GP905. The solution to the leak, as far as Shepard was concerned, involved the elimination of the temperature differential in GP922 by the re-introduction of warm lean oil.
- 13.26 Bill Visser was a plant supervisor on duty at Longford on the day of the incident. He had 18 years of experience. He thought that the only consequence of the loss of lean oil flow in GP1 was its effect on the quality of gas produced. His decision to shut down the flow of inlet gas was made to avoid the production of off-specification gas. He said that he did not know of any danger involved in the loss of lean oil flow. Visser was unaware of the cold

temperature rating of vessels. He did not understand, nor did his training permit him to understand, any danger associated with cold brittle fracture.

- 13.27 Had the operators, supervisors and superintendents dealing with the problems in GP1 on 25 September 1998 had the opportunity to enlist the advice and assistance of the plant manager or the operations manager, it would not have helped. Will Harrison, an engineer and Longford plant manager, was unaware of the critical operating temperatures of GP905 and GP922. He did not know that the loss of lean oil circulation would result in the plant getting colder, nor did he know of the dangers of cold metal embrittlement. The fact that lean oil flow had stopped for some hours would not have “rung a specific alarm bell”. In any event, on the day of the accident, Harrison was attending a meeting at Long Island Point.
- 13.28 Peter Coleman was operations manager at Esso. His responsibilities included management of operations at the Longford plants. Harrison reported directly to Coleman. Coleman was an engineer. He had been operations superintendent at Longford between December 1993 and October 1994. Coleman agreed that the instruction given to operators “failed in arming them to recognise the significance of cold temperatures...there was clearly a lack of knowledge or understanding of cold temperatures.” He said he had no idea, before the accident, that a loss of lean oil flow for any length of time would be a hazard.
- 13.29 Esso challenged the evidence of the operators and, in particular, that given by Ward. It relied upon OIMS, its operator training programmes, the Red Book and expert evidence from witnesses such as Kenneth Baker. Baker said that the loss of lean oil circulation was a fundamental issue to be addressed in GP1. He said that operators failed to do things on the day of the accident “that are so basic in a lean oil plant....and so standard in the industry and in a plant of that type....”. He said that the hazards associated with the loss of lean oil flow were well known.
- 13.30 Esso also relied upon the evidence of Luke Musgrave, the Longford gas restoration project manager, to support its contention that operators were adequately trained in appropriate responses to the loss of lean oil circulation. In 1994, Musgrave had been appointed plant manager at Longford and he held that position until 1996 when Harrison took over. He gave evidence that he had knowledge of the consequences of the loss of lean oil flow and said that he acquired that knowledge from discussions with operators, reading the Red Book and from some courses which he attended. The discussions to which Musgrave referred were said to be with Ray Wilson, Peter Wilson (who died in the accident) Shepard and Brack. Musgrave said that as a result of those discussions he concluded that “They were aware of consequences associated with the loss of lean oil and in my training communicated some of



those consequences to me.” Evidence to that effect was not elicited from Ray Wilson or Shepard when they were in the witness box and the events of 25 September 1998 belie the knowledge which Musgrave said those witnesses had. Moreover, if Musgrave acquired the knowledge which he said he did, he did nothing as plant manager to ensure that the written operating procedures contained instructions to be followed in the event of loss of lean oil circulation.

- 13.31 The Commission concludes that the evidence of the operators and supervisors on the day of the incident best describes the state of their knowledge. Even if some aspects of that evidence can be criticised, the actual events which occurred on 25 September 1998 are a sure indication of a deficiency in the knowledge required to operate GP1 safely.

### ***Inadequate Supervision***

- 13.32 Quite apart from the adequacy of knowledge, the events leading up to the accident disclosed a number of instances where operators failed to adhere to basic operating practices. Some of these practices were written, for example, those relating to shift handover and operator log entries. These are discussed later in this chapter. Others would seem to be matters of common sense and include monitoring plant conditions, responding appropriately to alarms, reporting process upsets to supervisors and undertaking appropriate checks before making adjustments to process variables.
- 13.33 These failures were not confined to operators or to any one shift. Indeed, the evidence suggests that some of the failings were so prevalent as to have become almost standard operating practice. These practices could not have developed or survived had there been adequate supervision of day to day operations by Esso management. The change in supervisor responsibilities, discussed later in this chapter, may have contributed by leaving operators without properly structured supervision. Monthly visits to Longford by senior management failed to detect these shortcomings and were therefore no substitute for essential on-site supervision.

### ***OIMS Self Assessments***

- 13.34 Element 11 of the ECI Guidelines, which were translated into Esso’s OIMS Systems Manual, required a “process that measures the degree to which expectations are met” and regarded that requirement as essential “to improve operations integrity and maintain accountability”. That meant that Esso’s OIMS were required to include a system to ensure that these guidelines were met and, in particular, that Esso’s operations were assessed at predetermined frequencies to establish the degree of compliance.

13.35 An external assessment was carried out by a team under the leadership of Wayne Achee in March and April 1998. A report of the assessment was prepared and sent to Sikkel. The report acknowledged that the assessment was required by element 11 of the ECI Guidelines to determine the extent to which Esso was meeting the guidelines and the requirements of its individual management systems. The report noted that the assessment team had concluded that Esso had successfully applied OIMS and had a high level of management involvement and participation, presumably in that process.

13.36 The report further noted the following achievements:

- There was a common set of operating manuals, references and records which were identified and in place at all sites.
- There was an extensive set of operations and maintenance procedures which were updated at specified intervals as changes occurred.
- There was a good understanding of and high discipline in safe work routines and procedures.
- There was a structured and disciplined process in place for shift handover for offshore and onshore operating sites.
- There was a comprehensive incident reporting, investigation and analysis system which was well understood throughout the organisation. Esso personnel were well disciplined in following their procedures.
- Near miss reporting was actively encouraged by management and supported by Esso personnel.

13.37 These (and other) observations of the assessment team appear inconsistent with the Commission's findings concerning the failure of Esso to implement its own systems, particularly in relation to risk identification, analysis and management, training, operating procedures, documentation, data and communications. The Commission can only conclude that the methodology employed by the assessment team was flawed in that the team failed to identify significant deficiencies in the extent to which "individual EAL Management Systems" conformed to the guidelines, particularly in relation to GP1, and were implemented.

### ***Observations***

- 13.38 Evidence was given that OIMS was a world class system and complied with world's best practice. Whilst this may be true of the expectations and guidelines upon which the system was based, the same cannot be said of the operation of the system in practice. Even the best management system is defective if it is not effectively implemented. The system must be capable of being understood by those expected to implement it.
- 13.39 Esso's OIMS, together with all the supporting manuals, comprised a complex management system. It was repetitive, circular, and contained unnecessary cross referencing. Much of its language was impenetrable. These characteristics made the system difficult to comprehend both by management and by operations personnel.
- 13.40 The Commission gained the distinct impression that there was a tendency for the administration of OIMS to take on a life of its own, divorced from operations in the field. Indeed, it seemed that in some respects, concentration upon the development and maintenance of the system diverted attention from what was actually happening in the practical functioning of the plants at Longford.
- 13.41 However, the fundamental shortcoming was in the implementation of OIMS, as seen in the inadequate state of knowledge of Esso personnel of the hazards associated with loss of lean oil circulation in GP1 and of the actions which could be taken to mitigate such hazards. As a consequence of this lack of knowledge, practices adopted by operations personnel fell far short of good operating practice and were inimical to the safe operation of the plant on that day. Mark Sikkel, a director of Esso and the person responsible for exploration and production, accepted that the manner in which operators carried out their work was "an immediate and potent indicator of the success of management systems." Dr Raymond Stickles, an expert called by Esso, agreed.
- 13.42 Reliance placed by Esso on its OIMS for the safe operation of the plant was misplaced. The accident on 25 September 1998 demonstrated in itself, that important components of Esso's system of management were either defective or not implemented. If the implementation of OIMS by Esso was to be measured by the adequacy of its operating procedures, they were deficient and failed to conform with the ECI Upstream Guidelines or with the OIMS Systems Manual. If it was to be measured by reference to the actions and decisions of those persons who were attempting to resolve the process upsets on 25 September 1998, they were also deficient. The deficiencies were in the manner in which Esso dealt with the acquisition and retention of knowledge. This involved its training system, its operating procedures, its documentation and data system, and its communication system.

## ***RISK ASSESSMENT AND MANAGEMENT***

### ***OIMS***

13.43 The central importance of co-ordinated and planned hazard identification, assessment and control to the safe and efficient operation of a processing facility, is well recognised throughout the processing industry. Almost all modern processing operations have some form of risk management system designed to identify, evaluate and assess risks and to create systems for their control.

13.44 Element 2 of Esso's OIMS identified the risk assessment and management system. Esso's own expectations in relation to risk assessment and management were set out in the introduction to Element 2, where it was stated:

“The identification, assessment, mitigation and control of risks is a necessary part of oil and gas operations. This system is intended to ensure these activities are undertaken.”

“The objective of the risk assessment and management system is to ensure hazards are identified and risks evaluated throughout the life cycle of the operation from initial field survey to eventual facility de-commissioning. We recognise that comprehensive risk assessment can reduce risk and mitigate the consequences of safety, health, and environmental incidents by providing essential information for decision making.”

13.45 The methods by which risk assessment and management were to be carried out were detailed in the Risk Assessment Manual (RAMS). RAMS set out a systematic programme of risk assessment at three levels: “structured risk assessment”, “operational management” and “field risk control”. Each level applied different but related risk assessment techniques to different levels of Esso's operations, ranging from day-to-day operation of the plant by operations personnel to formal or structured risk assessment conducted by the Production Technology Department.

13.46 The highest level required planned hazard identification and risk assessment to take place in various circumstances. These assessments embraced Periodic Risk Assessments (PRAs) which were to take place at intervals specified by RAMS; Quantitative Risk Assessments (QRAs) which were detailed risk studies carried out as needed to assess specific major hazard risks; and triggered risk assessments which were scenario-based assessments prompted by the happening of particular events.



- 13.47 At the next level there were hazard identification techniques to be used by employees and management in the course of operations. These included the use of check lists, analyses based upon the question “what if?” and hazard and operability (HAZOP) studies, either prospective or retrospective, conducted when the need appeared to identify particular hazards involved in the operation of the plants.
- 13.48 At the lowest level there were hazard identification “tools” to be used by operators to identify hazards and mitigate risk on a daily basis. These tools, or techniques, primarily comprised “step back 5x5” (stepping back 5 paces and pausing for five minutes to reflect upon likely hazards) and task analysis.

### ***Hazard Identification***

- 13.49 The core ingredient of effective risk assessment and management is hazard identification. In the text “Loss Prevention in the Process Industries”, Professor F. P. Lees, a recognised expert on loss prevention, states:

“The identification of areas of vulnerability and of specific hazards is of fundamental importance in loss prevention. Once these [hazards] have been identified, the battle is more than half won.”

- 13.50 The crucial significance of hazard identification to effective risk assessment and management, was recognised by Esso and its parent, Exxon, in the Exxon Process Hazard and Operability Review, 1993:

“To prevent the undesirable consequences of accidents, one must first identify the hazards which can lead to accidents. Once the hazards have been identified, a major stumbling block to loss or accident prevention has been overcome.”

- 13.51 This point was illustrated by the Exxon model shown in Figure 13.1 of that Review. Put simply, hazard identification creates knowledge.

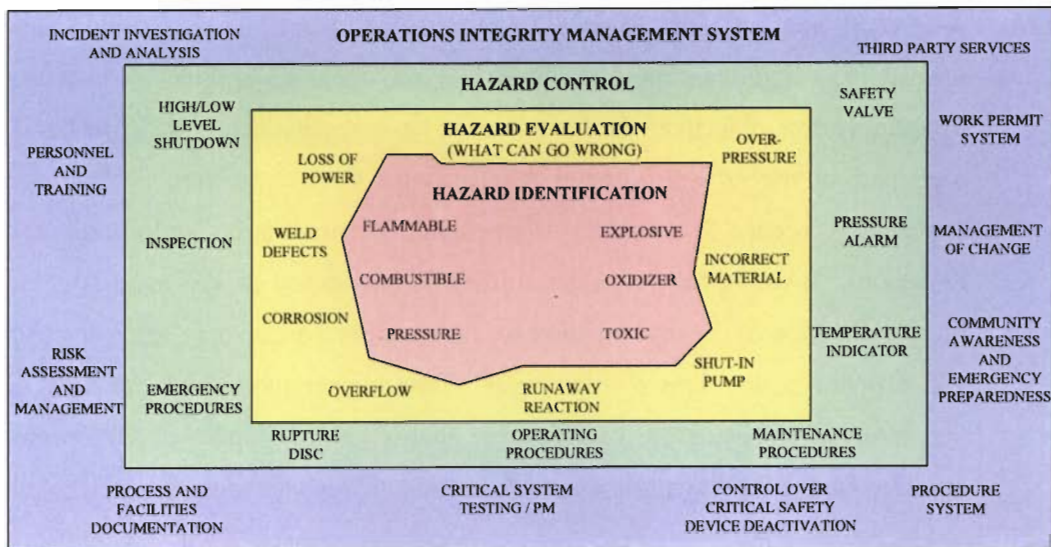


Figure 13.1 Exxon Hazard Management Process

### HAZOP Study of GP1

- 13.52 With the introduction of OIMS in the early 1990's, there was a requirement for the carrying out of HAZOP studies as part of the design process for new plant. OIMS also contained provision for retrospective HAZOP studies on existing plant, should they be called for. GP1 was constructed well before the introduction of OIMS and, indeed, before the use of HAZOP studies became common practice in the process industry. Following the introduction of OIMS, Esso recognised the need to undertake retrospective HAZOP studies of all its major facilities. Retrospective HAZOP studies were conducted for GP2 in September 1994, for GP3 in November 1994 and for the CSP in December 1995.
- 13.53 Esso recognised the particular significance of a HAZOP study for GP1, given the age of the plant, the modifications made to its initial design and the changes to design standards since the plant was built. These reasons grew stronger with the passage of time. Indeed, a HAZOP study for GP1 was planned to take place in 1995 and the cost of such a study was included by Esso in successive budgets during the years 1995 to 1998.
- 13.54 The HAZOP study planned for GP1 never took place. Various explanations were given for this failure. It was said that it would have taken a long time to complete and would have picked up too many little items. It was also said that Esso wanted to evaluate the HAZOP process more fully before undertaking such a study for GP1. Further, it was suggested that the resources required for a HAZOP study of GP1 could be more usefully allocated to higher priority areas such as the risks identified in a 1994 PRA. In the end, no satisfactory reason was given in evidence for its deferral or abandonment.

13.55 A HAZOP study of GP1 in accordance with Esso's methodology would have sought to identify "any significant route to a process upset, operating problem or hazardous incident". To achieve this objective, the study would have systematically described and questioned each part of the GP1 process to identify what deviations from design intention could conceivably occur. It would also have evaluated the causes and consequences of such deviations. It would have considered items of operability as well as safety. Not only that, but the direction of the investigation would have been dictated by reference to guide words which included the phrases "high level", "low temperatures" and "no flow". Given this systematic approach, it is inconceivable that a HAZOP study of GP1 would not have revealed factors which contributed to the accident which occurred on 25 September 1998. It would, for example have revealed the consequences associated with loss of lean oil flow and would have identified the procedures to be adopted in order to avoid dangerously low temperatures.

### ***The McNeil Report***

13.56 Esso's own investigation, which resulted in the McNeil Report, involved the production of a document which was apparently a draft to be used in the compilation of the final report. The draft document was seized by the Coroner shortly after the explosion and fire. It contained the unequivocal statement: "The lack of a detailed HAZOP for GP1 is considered a contributing factor to this incident". That statement did not appear in the McNeil Report in its final form, but there was no evidence to explain its exclusion. All the members of the investigating team were from overseas and were no longer in Australia and available to the Commission at the time of its hearings. Esso did not seek to call any member of the investigating team to give evidence. In the circumstances, the Commission concludes that the omission of the statement from the final report does not in any way detract from its force.

### ***PRA's of GP1***

13.57 Until October 1996, RAMS required that PRA's be carried out for existing production and processing facilities at intervals specified in a table contained in the manual. Sites were given priority so as to ensure that higher risk sites were more frequently re-assessed. Re-assessment intervals ranged from three years (Priority 1) to five years (Priority 3). GP1 was given the highest priority for the conduct of PRA's.

13.58 Notwithstanding the failure to carry out the HAZOP study planned for GP1, a PRA of GP1 was carried out in 1990 and again in 1994. The latter was in accordance with the existing RAMS timetable. In October 1996, however, a "rationalisation" of risk assessment under

OIMS was carried out. This resulted in the replacement of priorities for PRAs by a flat five year interval between PRAs for all onshore and offshore facilities.

- 13.59 There was little evidence of the nature of the 1990 PRA, although certain scenarios which it used were also used in the 1994 PRA. The 1994 PRA was, however, limited in scope because a HAZOP study for GP1 was then proposed for the following year. The 1994 PRA expressed this limitation as follows:

“The assessment targeted higher level risks, and was designed to complement forthcoming other more detailed studies, such as HAZOP, and QRA. It is understood that a detailed HAZOP study of Gas Plant 1 is proposed for mid-1995. Therefore the focus of this assessment was on analysing and identifying areas of risk not previously identified, or those not likely to be covered in the detailed HAZOP analysis” (emphasis added).

- 13.60 Accordingly, the 1994 PRA was directed away from process-related hazards and concentrated on hazards caused by mechanical equipment failure and operator error. Scenarios addressing the consequences of “low temperatures”, “high level” and “no flow” were not used. Indeed, no scenario was used which included any of the process upsets which occurred in GP1 on 25 September 1998.
- 13.61 Before the OIMS rationalisation in October 1996, a PRA of GP1 was planned to take place in 1997. As a consequence of the rationalisation and the introduction of a five year interval between PRAs, the PRA planned for GP1 in 1997 was postponed to 1999.

### ***Observations***

- 13.62 The combined affect of the failure to conduct a HAZOP study of GP1, the limitation placed upon the scope of the 1994 PRA and the postponement of the PRA planned for 1997 meant that there was no identification of major hazards in GP1 and, in particular, no identification of the hazards which revealed themselves on 25 September 1998. Notwithstanding the high aims of OIMS, no formal hazard identification or structured risk assessment of any kind took place in GP1 after 1994.
- 13.63 Despite the efforts of the Commission to ascertain whose decision resulted in the deferral or abandonment of a HAZOP study for GP1, no one would accept responsibility for the decision. However, the decision to defer the 1997 PRA was a decision of an executive committee of Esso’s Board of Directors. That decision must have been made with the



knowledge that the scope of the 1994 PRA was curtailed because of a planned HAZOP study which never took place.

- 13.64 Whatever the reason for failing to carry out a HAZOP study for GP1, the failure to do so carried with it the risk that hazards would remain unidentified and uncontrolled. The events of 25 September 1998 demonstrated the existence of such hazards. Had a HAZOP study of GP1 been conducted, as Esso initially believed it should, Esso would have acquired knowledge of those hazards which, as it transpired, were critical. In due course, that knowledge would have been disseminated by way of training, the development and use of procedures and the adoption of protective control systems. In short, the failure to conduct a HAZOP study of GP1 contributed to the disaster which occurred on 25 September 1998.

### ***MANAGEMENT OF CHANGE***

- 13.65 Attached to and forming part of Element 7 was Esso's Management of Change Philosophy dated August 1993 (the philosophy). In the philosophy, Esso recognised that change was "necessary and desirable" as part of the operation of a facility but also recognised that "changes potentially invalidate prior risk assessments and can create new risks, if not managed diligently".
- 13.66 The philosophy contained management of change procedures to be followed in undertaking, amongst other things, any modification or addition to an existing facility. These procedures required any permanent change to an existing facility to be accompanied by a risk assessment of the change, consistent with the procedures in OIMS Element 2, "Risk assessment and management". The primary purpose of such an assessment was to determine the impact of the proposed change on the safe operation of the facility.
- 13.67 However, OIMS Element 2 did not identify any procedures for risk assessment associated with management of change. The only reference to this topic was in the following terms:
- "Production Technology operate within a management of change procedure which is consistent with the EAL management of change philosophy."
- 13.68 Moreover, neither OIMS Element 7 (Management of change) nor OIMS Element 2 (Risk assessment and management) made any attempt to define the breadth or scope of any risk assessment study to be undertaken to comply with management of change procedures.

### ***Condensate Transfer from GP1 to GP2***

- 13.69 Before 1992, all condensate produced in the lower section of the absorbers in GP1 was processed within GP1 by directing the flow of the condensate from the absorbers to the Condensate De-ethaniser, GP1106. In 1992, a modification was made to the absorbers to create an additional flow path for condensate from the lower section of the GP1 absorbers to the GP2 Demethaniser. The modification enabled the more efficient recovery of ethane, using the cryogenic processes within GP2, than was possible within GP1.
- 13.70 The condensate transfer line to GP2 was installed in late 1992, based on a design by a company called Restech Consultants. At the time of design, the modification was subject to a hazard identification study which applied the HAZOP guide word “technique”. However, the review differed from a full HAZOP study as defined in Esso’s HAZOP methodology. The scope of the study was confined to a consideration of the impact of the 1992 modification on the pipeline connecting the two vessels involved in the transfer process, namely the GP1 absorbers and the GP2 Demethaniser. The study made no attempt to identify hazards associated with, or to evaluate the impact of, the proposed modifications on other parts of GP1, particularly the vessels downstream from the absorbers in the ROD/ROF area.
- 13.71 Importantly, in considering the impact of the modification on the transfer pipeline, the 1992 study identified condensate carryover into the absorption oil system as a potential outcome of high levels of condensate in the absorbers. It did not, however, examine the effect of condensate carryover on vessels downstream from the absorbers in GP1. This was because of a conclusion reached by those involved in the study, that condensate carryover was “not a new phenomenon” and that it should “...be handled in the same way as it is handled now”. The study noted that no follow-up action was required.
- 13.72 Between 1993 and 1996, further modifications were made to the condensate transfer system to overcome operational problems. Unlike the 1992 modifications, these further modifications were not subjected to any hazard identification study before implementation. Further modifications to the process were implemented in 1997 in accordance with design modifications proposed by consultants, Shedden Uhde. These modifications were to overcome flow meter measurement problems occurring in the condensate transfer line.
- 13.73 A hazard identification study of similar scope to the 1992 study was undertaken to assess the impact of the Shedden Uhde modifications. Again, this study identified the potential for process upsets to cause carryover of condensate from the absorbers into the rich oil stream

but again, the study did not examine the potential impact of this carryover on existing vessels in GP1. Instead, the study dismissed this phenomenon as not significant.

- 13.74 The Shedden Uhde modifications were introduced into operation but did not work as planned. As a consequence, revised operating practices evolved to cope with these difficulties. These practices involved automatic valve adjustments (required to initiate and to terminate condensate transfer) being abandoned in favour of manual manipulation of valves by operators. These revised practices invalidated the previous risk studies undertaken, yet were not themselves the subject of any management of change risk assessment.
- 13.75 The end result was that by 1998, operators at Longford were regularly transferring condensate to the GP2 Demethaniser using a transfer system that had never been the subject of a comprehensive management of change risk assessment. Between 1992 and 1998, this system had been substantially modified from the original design in a way which invalidated the limited hazard identification studies undertaken in 1992 and 1997. As a consequence, for some time before the accident on 25 September 1998, operators were transferring condensate to GP2 for product recoveries without a full understanding of the potential hazards associated with the process.
- 13.76 As is now apparent, the cold temperatures resulting from the carryover of condensate from the absorbers into the rich oil stream was a central feature of the accident which occurred on 25 September 1998. Whilst condensate transfer was not taking place at the time of the accident, it was taking place between 3.20 pm on 23 September and 3.26 pm on 24 September. During this period, the cold temperature of the condensate passing from Absorber A to the Condensate De-ethaniser in GP1 contributed to an increase in the TC9B override of level control in Absorber B.
- 13.77 Moreover, although transfer ceased around 3.26 pm on 24 September, the setpoint adjustment required to increase the temperature of Absorber B (from  $-20^{\circ}\text{C}$  to  $-10^{\circ}\text{C}$ ) was not made until the night shift on 25 September when two separate adjustments were made. Thus, unnecessarily low condensate temperatures in Absorber A continued to contribute to override problems until well into the night shift leading up to the accident.
- 13.78 The need, during periods of condensate transfer, to operate the GP1 absorber bottoms at a lower transfer temperature than its design operating temperature, resulted in more frequent TC9B override of absorber level control and higher levels of condensate in the absorber bottoms. This in turn led to increased frequency of TC9B alarms and high level alarms for

the absorbers. As explained under the heading “Operation in alarm mode”, over time this led to a tolerance by operators of alarm conditions in the absorbers. The effect is to be seen in the operators’ failure to respond to absorber high level alarms and TC9B alarms in the days leading up to the accident.

### ***Relocation of Plant Engineers from Longford to Melbourne***

- 13.79 Until 1991, engineers were stationed at Sale and worked at the Longford plant daily. In doing so, they had a close involvement with the ongoing operation of the plant and constant interaction with operations personnel. This placed them in an ideal position to monitor the plant operating conditions and operator practices.
- 13.80 In 1992, Esso relocated all its plant engineers to Melbourne as part of a restructuring of the company. This relocation has been discussed in Chapter 2 and is further mentioned in relation to the role of plant surveillance discussed later in this Chapter.
- 13.81 The change appears to have had a lasting impact on operational practices at the Longford plant. The physical isolation of engineers from the plant deprived operations personnel of engineering expertise and knowledge which previously they gained through interaction and involvement with engineers on site. Moreover, the engineers themselves no longer gained an intimate knowledge of plant activities. The ability to telephone engineers if necessary, or to speak with them during site visits, did not provide the same opportunities for informal exchanges between the two groups, which are often the means of transfer of vital information.
- 13.82 The relocation of engineers qualified as a permanent change to operating practices requiring risk assessment and evaluation before implementation in conformity with Esso’s management of change philosophy. Yet such relocation was implemented without any such assessment ever taking place.
- 13.83 There were no experienced engineers on site at the time of the accident on 25 September 1998. Expert knowledge from that source, of plant operating parameters, of the metallurgical limits of equipment and vessels in GP1 and of the consequences of cold temperatures resulting from loss of lean oil circulation in the ROD/ROF area, were absent.

### ***Changes to Role and Responsibilities of Operators and Supervisors at Longford***

- 13.84 In mid-1993, changes were made to the respective roles and responsibilities of operators and supervisors at Longford. Further changes were made in 1996 and 1997 with the consequence that operators assumed a greater responsibility for the day to day operation of

the plant, including troubleshooting to overcome process irregularities. There was also a reduction in the number of plant supervisors and a reduction in the number of plant operating areas. These changes are more fully explained in Chapter 2.

- 13.85 These structural changes were clearly intended to alter operating and supervisory practices at the plant and thus required management of change risk assessment and evaluation pursuant to Esso's management of change philosophy. Again, no such assessment was carried out. Though the existence of a link between this failure and the occurrence of the accident is hard to evaluate, appropriate management of change risk assessment may have exposed important and relevant weaknesses in the level of operator knowledge, in training programmes, in communication systems, in operating procedures and in other aspects of Esso's management system.

### ***Reductions in the Numbers of Maintenance Personnel***

- 13.86 Reductions in the numbers of maintenance personnel at the Longford plant occurred between 1993 and 1998. These are discussed in Chapter 2. The evidence did not indicate that the changes to maintenance operations contributed to the occurrence of the accident on 25 September 1998. However, none of the changes were subject to any management of change risk assessment as required by OIMS.

### ***COMMUNICATION CONTROLS***

- 13.87 The safe and efficient operation of a processing facility depends to a significant extent upon the dissemination of information and knowledge amongst those involved in the operation of the plant. OIMS, as applied at Longford, required certain channels of communication in order to facilitate the exchange of information. For example, it was a requirement that operators use the handover at the end of each shift for this purpose. Apart from OIMS, there were other protective systems, such as alarms, to ensure that essential information about the process came to the attention of plant operators.
- 13.88 Also important in the operation of a processing facility is the existence of some means whereby the operation of the plant and the practices of operators are systematically monitored to eliminate unsafe or inefficient operations. There was no evidence that any system existed at Longford for the regular monitoring of operating conditions or operator practices.

### ***GPI Control Room Log and Shift Handovers***

13.89 To facilitate the communication of process information and knowledge amongst operations personnel, the Longford Work Management Manual procedure LWMM 070-012, required operators and supervisors:

- to conduct verbal handover communications at the start and finish of each operating shift; and
- to complete log entries in a designated log book at the conclusion of each shift.

13.90 The LWMM referred to is that reissued in October 1997. There was evidence of a draft Esso Work Management Manual, apparently issued in July 1998, which also listed the requirements for handover. However, it is unclear to what extent this document remained a draft on 25 September 1998. In any event, its requirements appear to have been more stringent than those of the LWMM and it is convenient therefore to proceed upon the basis that the LWMM contained the applicable instructions.

#### *Shift handovers*

13.91 The shift handover requirement can be stated simply. It required panel operators, at the conclusion of each shift, to "...meet with their relief in the Control Room to hand over the operation of their area and to discuss the content of the ... log".

13.92 A number of operations personnel were asked about the form and content of handover communications. On the whole, the evidence revealed that verbal discussions between operators usually did accompany shift change, but often without any real effort to convey process problems or to discuss the content of log entries. The length of the discussions tended to depend on the discretion of the operator and they predominantly concerned product issues, such as VENCORP gas demands or gas rates.

13.93 The evidence disclosed particular shortcomings in the handover discussions that took place for the shifts immediately before the accident on 25 September 1998.

13.94 Most significant was the content of the handover discussion at the commencement of the critical day shift on 25 September. There were shortcomings in the exchange of information that took place between the night shift operator, Olsson, and his relieving panel operator, Ward. Olsson identified problems which he had experienced during the night with the rate of condensate coming into the slugcatchers from offshore. He also made reference to cold condensate temperatures which he had experienced in Absorber B and to problems which he

had experienced in controlling the temperature of this absorber throughout the shift. He made no reference, however, to the off-scale, high condensate levels in Absorber B, or to the frequent occurrence of TC9B interference with level control, both of which he had experienced during the night. Nor did he make any reference to the frequent incidence of alarm warnings acknowledged by him during his shift. These warnings had accompanied the high condensate levels and the TC9B override. Nor did he convey to Ward the fact that the alarms for high Absorber B condensate levels and TC9B interference were still active at the change of shift, indicating not only that the levels were still high, but that level control had still not been regained by the time of the change.

- 13.95 Because the alarms associated with high condensate levels in Absorber B and TC9B override had been acknowledged well before the conclusion of his shift, Ward was not presented with any audible alarm signal for these alarms at the time he relieved Olsson. As a consequence, the active state of these alarms would not have been immediately apparent to him and would not have become apparent unless he looked at the status of those alarms on the Bailey alarm page.

*Control room and shift supervisors' logs*

- 13.96 The other method of communication upon handover was through the control room log. This log was kept on the control room desk. Panel operators were required to record in it "the activities that have taken place in their operating areas, during the shift". Those activities included changes made during the shift to key process parameters and the results of such changes, any process or machinery problems encountered, any safety systems or devices defeated (including bypasses in the outside areas) and any controllers that were being operated in manual and the reason why.
- 13.97 In practice, however, operators did not keep control room logs in accordance with the stated requirements. An examination of the GP1 control room log revealed that entries were usually short and often contained only limited process information. There was inconsistency in the way entries were made and in their subject matter. Process issues, if referred to, often received only scant attention. Standing on their own, log entries were often confusing and incomplete. On frequent occasions, panel operators made no log book entry at all at the conclusion of a shift.
- 13.98 The log book entries made by the GP1 panel operators leading up to the accident on 25 September 1998, did not contain any reference to the abnormal process conditions occurring in Absorber B. These conditions had been occurring almost constantly from the afternoon of 23 September until the accident.

- 13.99 The log book entries made by Olsson for the night shift preceding the critical shift suffered from the same defects. His entries made no reference to the high condensate levels in Absorber B, to the interference with absorber level control caused by the TC9B override, to the fact that the TRC3B bypass valve was being operated manually or to the difficulties he had experienced in controlling the temperature of condensate at the base of Absorber B in the absence of automatic temperature control.

### *Observations*

- 13.100 It was against this background of uninformative handover communications and log book entries that the loss of lean oil circulation, which preceded the accident on 25 September 1998, took place.
- 13.101 At the commencement of the day shift on 25 September 1998, the outgoing GP1 panel operator had an obligation to tell the relieving operator, not only about the cold temperatures in Absorber B, but about the off-scale levels of condensate in that vessel. Both of these conditions had existed for some time. Olsson should at least have told Ward about the almost constant occurrence of the Absorber B high level alarm and the TC9B alarm and the fact that such alarms were still active at changeover. Indeed, the purpose of the handover procedure as a communication tool was to ensure that important process information was passed on. In the same way, Olsson's log book entries at the conclusion of his shift could have been, and should have been, more informative. They should also have made reference to these matters.
- 13.102 At 7.30 am, Ward gave Rawson a direction to close the TRC3B bypass valve. As discussed in Chapters 3 and 5, this caused the temperature of condensate in the base of the absorber to plummet and exacerbated the conditions which brought about the shutdown of the GP1201 pumps at 8.19 am. In his evidence, Ward said that at the time of directing Rawson to close the TRC3B bypass, he was not aware of the high condensate levels in the base of Absorber B, nor of the very cold temperatures of the condensate. He said he had not been told about the high levels by Olsson. Whilst he did conduct his own Bailey checks following handover, he said he did not detect the off-scale, high levels in Absorber B. As a consequence he made the direction to Rawson without appreciating that it was inappropriate.
- 13.103 Had Ward's attention been directed to these matters he may well have taken steps to see that the temperature and level of condensate in Absorber B were more appropriately managed. He would not have directed Rawson to close the TRC3B bypass, as he did at 7.30 am. On



the contrary, it is likely that he would have given Rawson a direction to open rather than close it.

- 13.104 Had the shift handover communications been in accordance with the requirements laid out in the LWMM, reference would certainly have been made to the abnormal conditions in Absorber B and to the fact that the level of condensate in that absorber was still out of control. Similarly, had the control room log book been entered in a proper way, it would have made reference to these matters.
- 13.105 It may also be observed that the process difficulties experienced during the night shift were also known to the night shift supervisor, Wijgers. He had, during the course of the night shift, spent time with Olsson in the GP1 control room endeavouring to deal with the high levels of condensate in the slugcatchers. However, at the change of shift Wijgers made no mention of the abnormal conditions of Absorber B to the relieving supervisor, Visser.
- 13.106 As shift supervisors were not primarily responsible for process matters, their obligation to pass on at handover information regarding process upsets was different from that of operators. However, given the degree of Wijgers' personal involvement with the process difficulties experienced on the preceding night shift and his knowledge of the abnormal conditions in Absorber B, he should have passed on this information to the incoming supervisor, Visser. Whether or not Visser would have communicated such matters to Ward is not apparent, but it is reasonable to assume that he would have done so at the toolbox meeting immediately following the change of shift.
- 13.107 Shift handovers and log book entries were used ineffectively in the lead up to the accident on 25 September 1998. Moreover, laxity in the implementation of the handover requirements seems to have escaped scrutiny by management.
- 13.108 Log book entries were not subjected to any examination either by Longford plant management or by management in Melbourne. They do not appear to have been used by management as a means of monitoring process conditions at the plant nor were they passed on to any person or group in Melbourne for plant surveillance purposes. This is discussed in more detail later.
- 13.109 The shift supervisors' log was available to management personnel both at Longford and in Melbourne. Process upsets were not, however, generally included in that document. This was understandable, given the particular responsibilities of plant supervisors. It meant, however, that the keeping of the shift supervisors' log was not a substitute for a properly maintained control room log.

- 13.110 A field operators' log for the ROD/ROF area was located in the ROD/ROF hut. This log was destroyed in the fire that occurred following the accident on 25 September 1998 and was not available in evidence.

### ***Operation in Alarm Mode***

- 13.111 Many of the instrumentation control loops within GP1 had alarms. The purpose of the alarms was to facilitate safe and efficient plant operation by warning operators when process conditions within vessels or equipment strayed outside normal operating parameters. Normal operating parameters were defined by alarm range settings.
- 13.112 Instrumentation alarms were linked to a display in the control room. Each alarm had a loud audible signal as well as a visual display which would light up either on the alarm panel (if part of the original system) or on the Bailey panel (if part of that system).
- 13.113 Once activated, an alarm had to be acknowledged by a person in the control room, usually the panel operator. Acknowledgement was effected by pressing a button to silence the audible alarm. In the case of Bailey alarms, the visual alarm signal then remained active until the process condition monitored by the alarm was brought back within normal operating parameters. The alarm then reset automatically. In the case of the original alarm panels, the operator was required to reset the alarm manually after process conditions returned within alarm range settings.
- 13.114 There was evidence that in the GP1 control room it was common for a large number of alarms to be active at any one time. Many of these alarms were nuisance alarms activated because the process variable monitored by the alarm was operated at the upper or lower end of its operating range and was constantly moving in and out of alarm range. This caused frequent repetitive alarms. In his evidence, Wijgers said that nuisance alarms had the capacity to distract operators and frequently did. They could be very repetitive and could result in more important alarms not being picked up or noticed because their warning signals were lost amongst numerous other alarms.
- 13.115 In 1992, condensate transfer from GP1 to GP2 was introduced in order to recover ethane more efficiently. For this purpose, it was necessary to operate the absorber from which the transfer was taking place at a lower temperature than its normal operating temperature (i.e. -20°C to -25°C instead of -10°C). This practice caused TC9B to override the absorber level controls more frequently and consequently, raise the levels of condensate in the base of the absorbers. Accompanying these conditions were increases in the frequency of warning

alarms for TC9B and high absorber condensate levels. These alarm conditions were tolerated.

- 13.116 In his evidence, Cumming said that recently, the occurrence of high level alarms in the absorbers had become very regular. He said that at the time of the accident, it was common for condensate levels in the absorbers to be in alarm. However, he felt that the absorbers operated quite adequately with condensate levels moving in and out of alarm range, although this meant the high level alarms occurred frequently. These alarms had to be monitored, but response by manual adjustment was not necessarily required. However, if the alarm indicated that the condensate level had gone off-scale, then Cumming agreed that a process adjustment was required.
- 13.117 Wayne Olsson, the night panel operator for the night shift preceding the critical shift, also said that it was a relatively common practice for the absorbers to be operated with condensate levels in alarm. When giving his evidence, Olsson was shown the alarm log for the period from 7.00 pm on 24 September to the accident. He conceded that there had been a considerable number of Absorber B high level alarms, but said that this was not unusual. Moreover, he said that it was not unusual for the absorbers to be run with condensate levels in excess of 100%. Indeed, in his view, an absorber could run at such a high level for hours and did so on occasions. On the night shift preceding the accident, he operated the absorbers in this way and said that he saw no danger associated with the practice. He also said that it was quite common for the TC9B override alarm to be active for periods during a shift and for the plant to be run with TC9B in alarm.
- 13.118 Olsson conceded, when faced with PIDAS data and alarm records, that, whilst he did acknowledge active alarms during his shift, he did not make process adjustments in response to high condensate level alarms for Absorber B, nor in response to frequent TC9B alarms. In explaining this inaction, Olsson said that he did not react to these alarms because he saw them as a normal situation and he was not aware that such high levels could be dangerous.
- 13.119 The practice of operating the absorbers in alarm occurred not only through the preceding night shift, but over a number of shifts in the days leading up to the accident on 25 September 1998. This was readily apparent from the PIDAS records (see Figure 5.1) and from the alarm log data.
- 13.120 Indeed, it is evident that well before the accident, panel operators had become accustomed to the frequent occurrence of alarm conditions at the base of the absorbers. TC9B alarms and high level alarms for Absorber B had become frequent enough for such alarms to be

regarded as a nuisance rather than a warning of process upsets requiring attention. This goes some way in explaining the insensitivity of operators to such alarms in the lead up to the accident. It may also explain why Olsson did not mention to Ward either the frequent occurrence of these alarms during his shift or the fact that they were still active at handover.

- 13.121 The practice of operating the absorbers in alarm had a bearing upon the loss of lean oil circulation. Excessive condensate carryover could not have occurred if operators had responded appropriately to the alarm warnings in the GP1 control room in the period leading up to the accident on 25 September 1998.
- 13.122 Operators would, no doubt, have reacted more appropriately to high levels in the absorbers had they appreciated the potential for condensate carryover and the dangers associated with cold temperatures. But even without this understanding, operators did know that operation of the plant for any length of time in alarm generally carried risks with it.
- 13.123 There was no evidence of any system to give priority to important alarms. Good operating practice would have dictated that critical alarms be identified and given priority over other alarms. It would also have dictated that operators be informed of the correct way to respond to process upsets identified by the occurrence of critical alarms.
- 13.124 The lack of any system of priority for critical alarms may explain why Ward failed to respond promptly or adequately to the activation of the LFSD8 alarm at 8.20 am on the morning of the accident. This alarm, which warned of a low flow shut down of the GP1201 pumps, was critical because it warned the operator of loss of the protective lean oil circulation system. Yet it was apparently ignored by Ward. Moreover, there were no procedures to assist the operator to respond to such loss of flow. This, however, is discussed elsewhere.

### ***Monitoring of Operating Conditions***

- 13.125 Within each plant control room at the Longford facility, the performance of process instrumentation and control systems was recorded. Some 70% of the instrumentation control loops in GP1 were operated and made records using the original pneumatic control system. That is, air pressure signals were used as a vehicle for the transfer of process information from the plant to the control room. This information was recorded in the control room by pen and ink on paper charts. These charts continuously recorded temperatures, pressures and flows associated with the operation of equipment in the plant.

- 13.126 The remaining 30% of the instrumentation in GP1 was electronically operated. The process data was recorded by the Bailey system and also stored in the PIDAS database. Like ink and paper charts, PIDAS provided a continuous record of process information.
- 13.127 As is apparent from the technical investigation into the cause of the accident, process charts and the Bailey system records were a potentially valuable source of process information concerning the status of any part of the plant at a given time (for example at the time of the accident on 25 September). They could also be used to analyse process trends or patterns of operation over an extended period of time and so assist in the identification of potentially unsafe conditions.
- 13.128 However, the evidence before the Commission indicates that such records were not used as effectively as they might have been in GP1. Indeed it is possible that their ineffective use played a part in the occurrence of the accident on 25 September 1998.

#### *Use made of chart recordings*

- 13.129 A number of control room operators said they used charts, and to a lesser extent PIDAS records, to assist them to understand plant conditions during the course of their shift. They did not, however, appear to use such records as a means of monitoring the performance of the plant over an extended time. Panel operators did not, as a general practice, resort to charts or PIDAS records as a means of evaluating longer term process trends or longer term performance of particular items of equipment. They did, of course, evaluate the process from time to time by reference to the indicators on the controllers.
- 13.130 As with plant operators, plant supervisors had access to charts in the GP1 control room. They also had access to PIDAS information through a computer terminal located on the plant supervisor's desk. When in the control room, supervisors used charts and computer records to understand and assess the workings of the plant during their shift and, to a lesser extent, in undertaking plant surveillance through the course of the shift. There was, however, no evidence to suggest that supervisors analysed charts or used PIDAS recordings to monitor patterns in process variables or to conduct other forms of trend analysis. If supervisors did undertake such work, they did so only rarely, rather than as a matter of course. From 1997, plant supervisors were not expected to carry out this type of surveillance, nor was it their responsibility to monitor process operations in detail.

#### *The plant surveillance group*

- 13.131 In the 1970's Esso employed plant engineers on site at Longford. One such engineer who gave evidence to the Commission was Luke Musgrave. He was first employed by Esso as a

GP1 surveillance engineer in 1979. In this role his responsibilities involved monitoring recovery performances of the plant, assisting in the resolution of operating problems and maintaining a liaison between Esso and design engineers in relation to specific projects. He said that in carrying out these responsibilities, he regularly visited the GP1 control room where he perused charts and log books. He said that he had a lot of contact with both operations personnel and with the plant itself. He frequently assisted operators to resolve process problems including recurring problems. It is apparent that, as a surveillance engineer for GP1, Musgrave was actively engaged in plant operations and plant surveillance activities.

- 13.132 As observed in Chapter 2, on-site engineers were relocated to Melbourne in 1992. This relocation was followed by the creation of a new department within Esso management. Within this department a group was established known as the Plants Engineering Group. In 1995, this group was renamed Plants Surveillance Group. The functions of this group were outlined by Musgrave and were the subject of evidence by Harrison and Keen. All said that the group did not undertake off-site monitoring or surveillance of ongoing process conditions, nor was it part of the group's function to undertake these activities. Rather, the functions of the group were limited to work on specific engineering projects, although they were available for assistance with particular problems if requested. Typically, engineering projects related to the enhancement of product recovery.
- 13.133 Following the relocation, plant engineers based in Melbourne made frequent visits to the Longford plant so that some opportunity for surveillance activities existed. However, these occasions were obviously more limited than the opportunity presented by the constant exposure of onsite engineers to plant operations and to operations personnel. Off-site engineers do not have the same opportunities for day to day close contact as did onsite engineers.
- 13.134 The consequence of the relocation of plant engineers to Melbourne was that the important task of continuous monitoring of process conditions within the Longford facility was diminished. Moreover, what was done was no longer carried out by plant engineers. Instead, it was undertaken almost exclusively by operators and plant supervisors whose surveillance work was focused on immediate production requirements rather than trend analysis or the analysis of recurring process problems.
- 13.135 The lack of plant surveillance activity in GP1 was demonstrated by the lack of use made of process information. Electronically generated process information was automatically retained in the PIDAS database. However, it would seem that it was rarely, if ever, looked

at, let alone subjected to any trend analysis. The remaining 70% of process information for GP1 was to be found on chart recordings and was also not subjected to any trend analysis. This is apparent because there was no system in place for preserving such records either for surveillance purposes or for accident investigation and analysis. The evidence was that charts, once used, were discarded by operators. They were not stored or retained. Thus historical process information covering some 70% of GP1 operations was never reviewed by engineers for surveillance purposes, but simply thrown away. Charts were not even date stamped at their beginning and end to make analysis easier.

### *Observations*

- 13.136 Monitoring of PIDAS records for GP1 in the weeks and months prior to the accident would have identified consistent deviations from normal operation in the absorbers in the form of high condensate levels and TC9B interference with level control. It would also have identified the operator practice of operating the absorbers in alarm. Had there been surveillance by qualified engineers, there would have been an opportunity to detect and correct the operating practices which led to the accident on 25 September 1998.
- 13.137 In the Commission's view, the failure to undertake ongoing analysis and evaluation of process trends within GP1, diminished the likelihood that upsets such as those which contributed to the accident on 25 September 1998 (operating conditions in the absorbers or condensate carryover) would be detected and avoided by appropriate responsive action. Had regular surveillance of operating conditions in GP1 been undertaken by qualified engineers, warning signals relevant to the accident (low absorber operating temperatures, high condensate levels, frequent TC9B interference with level control, the occurrence of condensate carryover, operation "in alarm") would, in all likelihood, have been identified. This could have led to changes in operating practice for the absorbers. It could also have led to more rigorous monitoring of conditions in GP1. Also, in the Commission's view, the absence of regular monitoring of process operations by senior personnel in a high pressure hydrocarbon processing plant, which was not equipped with protective devices to make it completely fail-safe, exposed that plant to an unacceptable risk.

### ***INCIDENT REPORTING***

- 13.138 Element 9 of the ECI Guidelines contained an incident reporting procedure. This procedure was taken up by Esso as Element 9 in the OIMS Manual. At the commencement of OIMS Element 9, Esso recognised the utility of effective incident reporting in these terms:

“Effective incident investigation, reporting and follow-up are necessary to achieve operations integrity. They provide the opportunity to learn from incidents and to use the information to take corrective action to prevent recurrence”.

13.139 The actual procedure for the reporting of incidents was set out in another Esso manual called the Safety Management Manual (SMM). In its introductory paragraph, the SMM (SMM-150-100, p.5) stated:

“All incidents, no matter how minor, are to be reported immediately to the worksite supervisor. All incidents are to be recorded on the hard copy Esso Incident Form, regardless of whether the Profs reporting system is used”.

13.140 The SMM explained an “Incident” as an unplanned event that caused, or could have caused, injury or damage to personnel, property or the environment which, in the case of injury, involved an Esso employee or contractor, and in the case of damage to property, occurred at a place controlled by Esso or involved Esso property.

13.141 The SMM also included (SMM-150-302) a definition of “near miss” as:

“...an unintended or unwanted event or circumstance which under slightly different conditions would have resulted in an incident”.

13.142 So defined, a “near miss” would clearly qualify as a “incident” for the purpose of SMM incident reporting requirements.

13.143 The SMM also contained a classification system for the ranking of incidents according to their seriousness or potential seriousness. This was to ensure that appropriate resources were directed to investigation and follow-up. Incidents which were classified as serious had to be accompanied by a critical evaluation of all related OIMS systems and critical equipment, to detect weaknesses in such systems or equipment and to ensure preventative action was taken.

### ***Operating Practice***

13.144 The SMM definitions of “incident” and “near miss” were clearly wide enough to require operations personnel to report as an incident any serious process upset that occurred during the operation of the Longford plant. In practice, however, the obligation to report incidents was construed narrowly both by Esso management and by operations personnel. Process upsets were rarely, if ever, the subject of an incident report, unless they were accompanied by injury to persons or damage to property.



- 13.145 The consequence of this practice was that process upsets which may well have signified to qualified and experienced personnel, defective equipment, or inappropriate operating conditions or unsafe operating practices, were not brought to their attention. Thus, valuable opportunities to learn from process upsets were lost.
- 13.146 A pertinent example of such a lost opportunity was the failure of operations personnel to report the cold temperature incident which occurred on 28 August 1998. This incident is examined in detail in Chapter 12.

### ***Observations***

- 13.147 Those that gave evidence concerning the 28 August incident (the plant supervisor, Wijgers, and panel operator, Olsson) conceded that it had a number of unusual features which, with the benefit of hindsight, warranted its being reported. These features included the fact that a critical spare GP1202 pump was unavailable (due to maintenance), with the consequence that the seal failure on the remaining pump required the shutdown of GP1 to effect repairs; the fact that such shutdown and subsequent restart had to be undertaken without the assistance of appropriate operating procedures; the fact that the incident involved a leak at GP922; and most importantly, the fact that, during the course of the incident, clear evidence emerged in the form of ice on piping and vessels that unusually cold temperatures were being experienced in vessels which usually operated hot, raising concerns about brittle fracture.
- 13.148 Had the incident on 28 August 1998 been reported as it should have been, the danger of equipment becoming subject to dangerously low temperatures upon the loss of lean oil flow for any length of time would, in all probability, have become known as would the steps available to avert the danger. The failure to report this incident thus stands as another example of a failure in Esso's implementation of its management systems. In the case of the incident on 28 August, such failure deprived operations personnel of process information vital to the prevention of the incident on 25 September 1998.



# Chapter 14

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## THE REGULATORY ENVIRONMENT

### *APPLICATION TO EXTEND THE TERMS OF REFERENCE*

- 14.1 The Commission's Terms of Reference require it to inquire into and report upon the causes of the explosion and fire at Longford on 25 September 1998 and the failure of the gas supply from the Longford facilities. By cl.2 of the Terms, the Commission is also required to consider whether certain matters caused or contributed to the occurrence of the accident or the failure of gas supply. Clause 3 requires the Commission to identify the steps that should be taken by Esso or BHP to prevent a repetition of those occurrences. Finally, the Commission is directed to make such recommendations as it considers appropriate, including recommendations regarding legislative or administrative changes.
- 14.2 On 27 January 1999 an application was made on behalf of the Victorian Trades Hall Council (VTHC) for the Commission to recommend to the Victorian Government that it amend the Terms of Reference to include in cl.2, a paragraph (i) in the following terms:
- “The regulation of Esso and BHP's Longford operations by the Government of Victoria, its agencies and departments.”
- and to insert the words “the Government of Victoria, its agencies and departments” in cl.3 before the words “Esso and BHP”.
- 14.3 This application was supported by counsel for Esso and counsel for the Leader of the Opposition and Shadow Ministers. It was opposed by counsel assisting the Commission, counsel for the State of Victoria and counsel for the Insurance Council of Australia.
- 14.4 The Commission took the view that the Terms of Reference were a matter for government and that, in the absence of special circumstances, such as an inability to pursue its inquiry by reason of the scope of the Terms of Reference, it ought not to take the course suggested by the VTHC. As no special circumstances were seen to exist, the application was refused.
- 14.5 Subsequently, on 30 March 1999, counsel for Esso sought to tender in evidence a bundle of documents dealing with the supply of gas from sources outside the facilities at Longford. The basis for doing so was that the Commission could not recommend steps to be taken by

Esso or BHP to prevent or lessen the risk of a further disruption of supply from those facilities without receiving evidence of what others, including the Victorian Government, could or should have done to ensure alternative supplies. Esso further submitted that, for similar reasons, the Commission could not make recommendations regarding legislative or administrative changes in the absence of evidence of the kind it sought to tender.

- 14.6 The Commission ruled that cl.3 of the Terms of Reference restricted it to a consideration of the facilities at Longford and the steps which ought to be taken there by Esso or BHP to prevent a recurrence of the events of 25 September or a further disruption of the gas supply from those facilities. It took the view that the Terms of Reference did not warrant it embarking on a more general inquiry into gas supply in Victoria: an inquiry which would be expensive and time consuming. Further, it considered that the direction in the Terms of Reference, requiring the Commission to make recommendations arising out of its inquiry, was circumscribed by the ambit of the inquiry it was required to make. On this basis it ruled that the documents that Esso sought to tender were not relevant.

### ***COMPLIANCE BY ESSO AND BHP WITH RELEVANT STATUTES AND REGULATIONS***

- 14.7 In considering whether certain factors caused or contributed to the occurrence of the incident and failure of gas supply, the Commission is required by paragraph 2(h) of the Terms of Reference, to consider “any breach of, or non-compliance with, the requirements of any relevant statute or regulation by Esso or BHP”.
- 14.8 Apart from a failure on the part of Esso to comply with the obligations imposed by s.21 of the *Occupational Health and Safety Act 1985 (Vic)* it was not submitted that there was a breach of, or non-compliance with, any other legislation which caused or contributed to the accident. Other offences were referred to, but without any suggestion of a causal connection between them and the accident on 25 September 1998. Rather, emphasis was placed upon the failure of the regulatory regime which governed Esso on 25 September 1998 to prevent the accident. That is a matter which is dealt with later in this chapter.
- 14.9 Section 21 of the *Occupational Health and Safety Act 1985*, so far as is relevant, provides:

- (1) “An employer shall provide and maintain so far as is practicable for employees a working environment that is safe and without risks to health.

(2) Without in any way limiting the generality of sub-section (1), an employer contravenes that sub-section if the employer fails –

- (a) to provide and maintain plant and systems of work that are so far as is practicable safe and without risks to health;
- (b) to make arrangements for ensuring so far as is practicable safety and absence of risks to health in connection with the use, handling, storage and transport of plant and substances;
- (c) to maintain so far as is practicable any workplace under the control and management of the employer in a condition that is safe and without risks to health.
- (d) .....
- (e) to provide such information, instruction, training and supervision to employees as are necessary to enable the employees to perform their work in a manner that is safe and without risks to health.”

14.10 Under s.47 of the Act, failure to comply with any of its provisions constitutes an offence against the Act.

14.11 The conditions prevailing in GP1 on 25 September 1998 clearly did not constitute a working environment that was safe and without risks to health. The relevant plant and system of work was not safe and without risks to health. The arrangements for the handling of hydrocarbons in GP1 on 25 September did not ensure safety and the absence of risks. The workplace in GP1 on that day was not in a condition that was safe and without risks to health. And Esso had not on that day provided such information, instruction, training and supervision to its employees as was necessary to enable them to perform their work in a manner that was safe and without risks to health.

14.12 Save for paragraphs (d) and (e) of s.21, the obligations imposed by that section are not absolute, but extend only so far as it is practicable to comply with them. However, the failure of Esso to provide a safe working environment in GP1 on 25 September 1998 was the result of its having failed to take measures which were plainly practicable. In order to provide a safe working environment there could and should have been appropriate operating procedures to deal with the loss of lean oil circulation, cold temperatures and the shutdown and start up of the plant. Furthermore, the operators and supervisors could and should have

known of and understood the real hazards confronting them on the day. These matters are discussed in other Chapters of this report.

- 14.13 Whilst there may have been breaches by Esso of other legislative provisions, such breaches must, if causally related to the occurrence of the accident, be encompassed by s.21 of the *Occupational Health and Safety Act*. That provision covers all the significant factors contributing to the accident and it would be otiose to pursue the question whether there were other offences committed by Esso and, if so, whether they contributed to the events of 25 September 1998.
- 14.14 For example, it would appear that on 25 September 1998, Esso's license under the *Dangerous Goods Act* 1985 (Vic) had expired. It was required to hold a license to keep dangerous goods under the *Dangerous Goods (Storage and Handling) Regulations* 1989. Failure to hold such a license was an offence under s.21(2) of the *Dangerous Goods Act*. The license held by Esso expired on 26 August 1998. In April 1998 it had initiated an application for the renewal of the license. Following site inspections on 31 July 1998, Esso wrote to the Victorian WorkCover Authority (VWA), which administered the Act, and formally applied for a renewal. On 14 August Esso wrote to VWA and provided it with an amended manifest and site plan to replace those initially provided. It enclosed a cheque for \$6,962.00 being the fee for the new license. VWA received the letter on 18 August 1998. Late in the afternoon of 25 September 1998 VWA realised that Esso's license had not been formally renewed. It appears that, save for a computer problem in relation to the generation of the license, it would have been granted by then. On 28 September 1998, after additional data was entered, VWA's computer system generated a license for the Longford site.
- 14.15 Whatever else may be said of its failure to hold a valid licence on 25 September 1998, it is clear that, if Esso were at fault, it was only in the most technical sense and that this circumstance did not cause or contribute to the events of 25 September 1998. The Terms of Reference do not authorise an inquiry into the reasons for the delay on the part of VWA in furnishing Esso with a license.

### ***Legislative Background***

- 14.16 Until 1985, the legislative scheme in Victoria dealing with occupational health and safety was prescriptive. That is to say, it laid down specific requirements, compliance with which was supervised by government agencies. For example, there was legislation dealing separately with disparate matters such as pressure vessels, hazardous substances, scaffolding and lifts and cranes. Following the 1972 Robens Report in the United Kingdom, a decision was made to change, at least in part, from a prescriptive system to one that was performance

based, that is to say, one which enunciated the basic and over-riding responsibilities of employers and employees. The report (Paragraph 130) explained that system as follows:

“A positive declaration of the over-riding duties, carrying the stamp of parliamentary approval, would establish clearly in the minds of all concerned that the preservation of safety and health at work is a continuous legal and social responsibility of all those who have control over the conditions and circumstances under which work is performed. It would make clear that this is an all-embracing responsibility, covering all workpeople and working circumstances unless specifically excluded.”

- 14.17 The result in Victoria was the enactment in 1985 of the *Occupational Health and Safety Act* and the *Dangerous Goods Act*. Section 21 of the *Occupational Health and Safety Act*, which is set out above, is one of the two sections (the other being s.22) which imposed the primary obligation upon an employer to provide and maintain a safe workplace and working environment, leaving it to the employer to identify the specific steps required for the carrying out of that obligation. On the other hand, the *Dangerous Goods Act* controlled the handling of dangerous goods through regulations which set out detailed safety prescription and imposed a system of licensing with respect to premises upon which dangerous goods are stored, such as Esso’s premises at Longford.
- 14.18 From 1986, the Department of Labour was responsible for the administration of both Acts. The Department of Labour had previously been known as the Department of Employment and Industrial Affairs which had earlier taken over the responsibilities of the Department of Labour and Industry. That Department ceased to exist.
- 14.19 Even after 1985, the Department of Labour had responsibility for the inspection and approval of pressure vessels (and later the Department of Business and Employment) under the *Boiler and Pressure Vessels Act* 1970 (Vic). Notwithstanding the intended change from a prescriptive to a performance based system under the *Occupational Health and Safety Act*, the change took time. Inspection and approval of pressure vessels by government agency inspectors continued until 1996.
- 14.20 In 1991, the Occupational Health and Safety Authority was established under the Department of Labour with responsibility for the administration of the *Occupational Health and Safety Act*, the *Dangerous Goods Act*, the *Boiler and Pressure Vessels Act* and other enactments and regulations applicable to Esso’s operations at Longford. Until the creation of the Occupational Health and Safety Authority those enactments and regulations had been administered by the Occupational Health and Safety Division of the Department of Labour.

- 14.21 The Occupational Health and Safety Authority is not to be confused with the Occupational Health and Safety Commission, established under the *Occupational Health and Safety Act* in 1985, being a body responsible for policy development.
- 14.22 In 1992, responsibility for the administration of occupational health and safety legislation in Victoria was transferred from the Department of Labour to the Department of Business and Employment. The Occupational Health and Safety Authority administered two divisions within the Department of Business and Employment. One division was concerned with health and safety and the other with chemicals and operating plant. In the same year, the *Accident Compensation (WorkCover) Act* 1992 established the VWA and abolished the Occupational Health and Safety Commission.
- 14.23 In 1995, the Occupational Health and Safety Authority was renamed the Health and Safety Organisation. In 1996 the Health and Safety Organisation was merged with the VWA which, until that time, had been responsible for the administration of the workers compensation schemes under the *Accident Compensation Act* 1985.
- 14.24 The *Accident Compensation (Occupational Health and Safety) Act* 1996 (Vic) effectively transferred to the VWA the powers and functions previously exercised by the Department of Business and Employment (and before that the Department of Labour) in relation to occupational health and safety.
- 14.25 In July 1995, the *Occupational Health and Safety (Plant) Regulations* came into operation revoking regulations previously made under the *Boiler and Pressure Vessels Act* and some earlier regulations made under the *Occupational Health and Safety Act*. The *Boiler and Pressure Vessels Act* was also repealed by proclamation made pursuant to s.2 of the *Occupational Health and Safety Act*. Under the new plant regulations a duty was imposed upon employers, such as Esso, to ensure that all hazards associated with the operation of its plant were identified. However, governmental inspection of pressure vessels continued until 1996. See *Occupational Health and Safety (Plant) Regulations* 1995, Regulations 702, 703, 704. Those regulations had the effect of shifting the obligation to inspect boilers and pressure vessels from a government agency to the employer.
- 14.26 Pursuant to its obligations under the new plant regulations, Esso developed a system for the inspection of pressure vessels at Longford and for keeping records of those inspections. It has not been suggested, nor does the Commission find, that there was any deficiency in that system or its implementation which caused or contributed to the accident on 25 September 1998.

## ***Safety Case***

- 14.27 In 1995, the National Occupational Health and Safety Commission was established under the *National Health and Safety Commission Act 1995 (Cth)*. In 1996, it published a National Standard for the Control of Major Hazard Facilities and a National Code of Practice for the Control of Major Hazard Facilities. The code of practice is a document prepared for the purpose of advising employers and workers of acceptable ways of achieving the national standard. The standard and code were prepared in the expectation (on the part of the Commission and the Commonwealth Government) that they would be given legislative force in the States and Territories.
- 14.28 The standard, which of itself has no legislative force, creates a framework for those managing major hazard facilities (MHFs), within which to identify and assess hazards and to control those hazards when identified. Compliance with the standard remains voluntary in Victoria.
- 14.29 Thus, both the national standard and the *Occupational Health and Safety (Plant) Regulations* require the identification and control of hazards. However, the national standard differs from the regulations in that it requires the operator of a MHF to forward a safety report to the relevant public authority with the responsibility of controlling MHFs. Such a report must constitute a written presentation of the technical, management and operational information covering the hazards and risks of the facility and their control, and provide justification of the adequacy of the measures taken to ensure the safe operation of the facility.
- 14.30 The requirement of a safety report (or safety case as it is sometimes described) has for some time been recognised as one of the most effective means of risk management where reliance is placed upon self-regulation. The safety case method of risk management emerged in Europe after the occurrence of disasters involving the release of flammable chemicals at Flixbrough in the United Kingdom in 1974 and of toxic chemicals at Seveso in Italy in 1976. A directive of the European Commission, known as the Seveso Directive, published in 1982, required member states to develop and implement regulations directed to the safety of major hazard sites. The directive did not extend to offshore facilities. After a series of catastrophic explosions and fires on an offshore platform, known as Piper Alpha, in 1988, an inquiry, chaired by Lord Cullen, focused attention upon the safety case method by recommending the extension of its application to offshore facilities. Esso has adopted the safety case model for its offshore facilities but not for its onshore facilities. This may be explained by the absence of any obligation requiring it to do so.



- 14.31 Regulations promulgated under the Commonwealth *Petroleum (Submerged Lands) Act 1967* (Cth) require the consent of the Designated Authority to construct or install a facility and to use a facility offshore. Obtaining consent entails the submission and acceptance of a safety case. In the case of Victoria, the Designated Authority is the Minister for Agriculture and Resources. The Designated Authority must accept the safety case if it is satisfied that it is appropriate to the facility and complies with the regulations. The safety case must be revised at least every five years and also in the event of relevant developments in technical knowledge, proposed modifications or changes to, or the decommissioning of, the facility. The regulations are the *Petroleum (Submerged Lands) Management of Safety on Offshore Facilities Regulations 1996*. Once accepted the safety case becomes the standard against which safety performance is assessed.
- 14.32 Not only is a safety case required for installations offshore, but the requirement to submit a safety case was recently introduced by regulations under the *Gas Safety Act 1997* (Vic). The *Gas Safety Act* and the *Gas Safety (Safety Case) Regulations 1999* require a gas company to submit a safety case to the Office of Gas Safety. The safety case must be in writing and comply with the regulations. The Office may require the safety case to be independently validated. The Office must accept a safety case if it is satisfied that it is appropriate for the facility to which it applies and complies with the Act and regulations. As may be expected, there is considerable uniformity in the safety case regimes of the Commonwealth and State. Neither applies by force of law to Esso's operations at Longford.

### ***Observations***

- 14.33 The regulatory regime covering Esso's operations at Longford was thus less stringent than for its facilities upstream from Longford and now for the gas transmission and distribution facilities downstream from Longford. Had Esso been required to submit a safety case with respect to its facilities at Longford before 25 September 1998, it is likely that it would have identified the very hazards which were in evidence on that day, hazards which a proper HAZOP study of GP1 would also have identified.
- 14.34 The Commission notes that the *Dangerous Goods (Storage & Handling) Regulations 1989* were amended in 1997 to enable operators of MHFs to obtain exemptions from certain prescriptive provisions contained in the regulations if they could demonstrate compliance with the national standard. There is no evidence that Esso ever sought such an exemption.
- 14.35 In a report prepared for the VWA by Det Norske Veritas and AON Pacific Risk Consultants in March 1999, the VWA was advised, among other things, to establish a centralised major hazards unit (MHU), reporting directly to the Director of Field Services. The report noted

- that in order for the Unit to be effective, it would have to be made up of highly skilled and experienced individuals. It would also have to establish credibility within industry.
- 14.36 The authors of the report proposed that the MHU personnel be skilled in process engineering, software, safety systems, risk analysis, emergency planning and auditing. A team approach was contemplated in recognition of the reality that, while members would have certain general skills, they would also have an area of specialist knowledge.
- 14.37 The report proposed the regulation of MHFs by the MHU, including a requirement for compliance with the national standard. Systematic audits were proposed. However, the report correctly included an expression of uncertainty about the VWA's ability to implement the safety report regime in the absence of enabling legislation or regulations. It was acknowledged that the national standard otherwise provided a good foundation for this regime.
- 14.38 It may be argued that the existing law in Victoria authorised the VWA to require Esso to prepare and submit a safety case or safety report of the kind required under the *Petroleum (Submerged Lands) (Management of Safety on Offshore Facilities) Regulations* or in conformity with the national standard. There is certainly scope under the *Occupational Health and Safety Act*, the *Dangerous Goods Act* and the regulations made thereunder for inspectors to impose conditions or give directions or notices in certain circumstances. However, the use of such powers to introduce a new and important risk management regime would be inappropriate. The conditions, directions and notices are, for the most part, open to appeal. There is no statutory procedure dealing with the VWA's response to the preparation and submission of a safety case. Moreover, the legal foundation for such a course is doubtful.
- 14.39 In April 1999, the VWA proposed to the Victorian Government that compliance with the national standard should be compulsory for operators of MHFs. Western Australia is the only state to have given legal affect to the national standard. The VWA also recommended to the Victorian Government that it should make new regulations designed to enforce the national standard. It proposes that those standards should be enforced at Longford and at other MHFs.
- 14.40 The Commission is required by its Terms of Reference to make such recommendations arising out of its inquiry as it considers appropriate, including recommendations regarding any legislative or administrative changes that are necessary or desirable. It has reached the conclusion that one legislative change which is both necessary and desirable is legislation

requiring the operation of an MHF such as Esso's Longford facility, to conform to a safety case or safety report procedure. The *Petroleum (Submerged Lands) (Management of Safety on Offshore Facilities) Regulations* provide a sound model, as does the *Gas Safety Act* and the regulations made under that Act. It is anomalous that Longford should be exempt from such a procedure, in contrast to facilities connected with the Longford plants both upstream and downstream. But far more importantly, the imposition of a safety case or safety report procedure at Longford would go a long way towards avoiding a repetition of the accident at Longford on 25 September 1998.

- 14.41 It has been suggested that there is a conflict between the role of the VWA with respect to accident compensation and its role as the supervisor of workplace safety regimes. The Commission is in no position to reach a conclusion whether such a conflict exists, but it is clear that if there is to be a MHU within the VWA, it should be given the independence necessary to ensure that any conflict is eliminated.

# Chapter 15

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## CONCLUSIONS AND RECOMMENDATIONS

### *TERMS OF REFERENCE – CLAUSE 1*

- 15.1 The primary task of the Commission has been to inquire into and report upon the causes of the explosion and fire which occurred at Longford on 25 September 1998 and the failure of gas supply from those facilities following the explosion and fire.

### *The Immediate Causes*

- 15.2 The immediate causes of the explosion and fire may be summarised in simple terms. A loss of lean oil circulation in GP1 occurred when the GP1201 pumps stopped. There was a failure to restart these pumps and they remained inoperative for some hours. The consequence was that a number of vessels were deprived of a flow of hot lean oil which, if the plant had been operating normally, would have served to heat them. The purpose of those vessels was to exchange heat with cold rich oil flowing from the absorbers.
- 15.3 The absence of hot lean oil allowed the cold liquid from the absorbers to chill those vessels to a temperature in the vicinity of  $-48^{\circ}\text{C}$ . One of the vessels involved was GP905. The reduction in temperature of that vessel caused the embrittlement of its steel shell. When hot lean oil was re-introduced into the vessel it ruptured by way of brittle fracture at its eastern end, releasing a volume of hydrocarbon vapour which travelled towards the area of the fired heaters where it ignited, causing an explosion and fire. There followed further explosions as the initial fire impinged on the piperack at Kings Cross and caused pipes to fail.
- 15.4 The explosions and fire led to the three gas plants at Longford being shut down with a consequent failure of gas supply from those facilities. The resumption of gas supply commenced on 4 October 1998 and was completed by 14 October 1998. The time taken to commence the restoration of the gas supply was due to the need to extinguish the fires in GP1 and to ensure the complete isolation of GP1 and the CSP from GP2 and GP3.
- 15.5 More than one factor contributed to the tripping of the GP1201 pumps. That is dealt with in Chapter 10. It is sufficient to say here that high levels of condensate in Absorber B led to condensate entering the rich oil stream. This in turn led to an upset in the ROD which resulted in a heavy carryover of liquid and vapour from that vessel into the lean oil stream.

As a consequence, the level in the Oil Saturator Tank was raised and the level controller for that vessel closed a level control valve to restrict the flow from the GP1201 pumps. This caused a low flow shut down switch in the lean oil system to shut down those pumps.

### ***The Real Causes***

- 15.6 Notwithstanding the matters mentioned above, the conclusion is inevitable that the accident which occurred on 25 September 1998 would not have occurred had appropriate steps been taken following the tripping of the GP1201 pumps. When efforts to restart those pumps proved unsuccessful, it should have been realised immediately that cold temperatures would ensue downstream from the absorbers and render vessels not designed to operate at low temperatures dangerous. Had this been realised, steps could and should have been taken to isolate the outlets of both rich oil and condensate from the absorbers in order to prevent those cold temperatures from developing in the ROD/ROF area. Those who were operating GP1 on 25 September 1998 did not have knowledge of the dangers associated with loss of lean oil flow and did not take the steps necessary to avert those dangers. Nor did those charged with the supervision of the operations have the necessary knowledge and the steps taken by them were inappropriate. The lack of knowledge on the part of both operators and supervisors was directly attributable to a deficiency in their initial or subsequent training. Not only was their training inadequate, but there were no current operating procedures to guide them in dealing with the problem which they encountered on 25 September 1998.

### ***TERMS OF REFERENCE – CLAUSE 2***

- 15.7 The Commission is required to inquire into and report upon whether a number of specified factors caused or contributed to the explosion, fire and failure of gas supply. It is convenient to deal with each of these factors in turn.

- **The design of the Longford facilities, including the interdependence of (i) the plants and other components which comprise these facilities, and (ii) the Longford facilities at or upstream of the Esso site at Longford.**

The build up in the level of condensate in Absorber B on 25 September 1998 was the result of the level control being overridden by TC9B. The effect was to reduce the flow of condensate through heat exchanger GP919 and to increase condensate levels in the absorber. TC9B was intended to protect the Condensate Flash Tank from low temperatures. This was particularly important when condensate was being transferred from GP1 to GP2 because transfer required the temperature of the condensate to be

reduced to -20°C compared with -10°C under normal operating conditions. The control system had been changed when the condensate transfer equipment was installed.

The design of the override as a protection against low temperature in the Condensate Flash Tank was inappropriate in circumstances where it was impossible for operators to discern the level of condensate in the absorbers when levels rose above the point at which they could be monitored. The attempt to protect the Condensate Flash Tank caused a serious problem in the absorbers. Whilst this aspect of the design of GP1 cannot be said to have been an ultimate cause of the explosion and fire, it exacerbated the circumstances which led to the tripping of the GP1201 pumps and the loss of lean oil flow. It undoubtedly accelerated the cool down of the plant following loss of lean oil.

In addition, the design of the ESD system in GP1 did not allow the isolation of the inventory of flammable liquid and vapour within the major vessels in the ROD/ROF area. In particular, the large inventory of lean oil in the ROF was not isolated upon the operation of the ESD system. This shortcoming contributed to the explosion and fire by allowing a significantly large quantity of fuel to escape from the ruptured vessel.

Lack of isolation between the CSP and GP1 and the contents of the pipework passing through the Kings Cross intersection also contributed to the fire in that a number of sources of fuel from the CSP had to be manually isolated during the afternoon of 25 September to reduce the size of the fire. Had the ESD system of GP1 and the CSP automatically isolated these sources of fuel, the consequence of the conflagration would have been less severe. Even if reliance had been placed upon manual isolation, there was no real plan or philosophy to guide such an operation.

The Commission does not consider that the design of the facilities at, or upstream from, the Esso site at Longford otherwise caused or contributed to the occurrence on 25 September 1998.

- **Operating standards, practices and policies**

Had a HAZOP study for GP1 been carried out as planned, the operators and supervisors in that plant on 25 September 1998 would not have remained ignorant of the hazards associated with a loss of lean oil flow and consequent low temperatures. They would have been instructed in the appropriate procedures to deal with the situation which arose on that day. The failure to conduct a HAZOP study or to carry out any other adequate procedures for the identification of hazards in GP1 contributed to the occurrence of the explosion and fire.

The training of its personnel to operate or supervise a potentially hazardous process was the responsibility of Esso and it failed to discharge that responsibility effectively. Whilst criticism can otherwise be made of certain aspects of the plant, its design and operation, the ultimate cause of the accident on 25 September was the failure of Esso to equip its employees with appropriate knowledge to deal with the events which occurred. Not only did Esso fail to impart that knowledge to its employees, but it failed to make the necessary information available in the form of appropriate operating procedures. The lack of operating procedures to deal with the loss of lean oil circulation, low temperatures and the shutdown and start up of GP1 combined with the inadequate training of personnel meant that the response to the situation which arose on 25 September 1998 was inappropriate and led to the occurrence of the explosion and fire. The lack of proper operating procedures contributed, therefore, to the occurrence.

Appropriate supervision of operators to ensure adherence to basic operating practices was also a responsibility of Esso management. The investigation of the events leading up to the accident revealed a number of occasions when operators failed to adhere to rudimentary operating practices. These included failures to monitor plant conditions, respond appropriately to alarms, report process upsets to supervisors and undertake appropriate checks before adjusting process variables. Had operating practices been more closely monitored and supervised by Esso management, these departures from appropriate operating practices would have been detected and remedied.

The reduction of supervision at Longford, including the transfer of engineers to Melbourne, necessarily meant a reduction in the amount and quality of the supervision of operations there. There was a correspondingly greater reliance by Esso on the skill and knowledge of operators. Whilst it is not possible to discern any direct connection between the level of supervision and the accident on 25 September 1998, the Commission considers that it was probably a contributing factor.

- **Maintenance standards, practices and policies**

Whilst criticism has been directed at Esso's reduction of its maintenance staff at Longford and its allocation of priority to work order requests, the Commission finds that Esso's standards, practices and procedures with regard to these matters did not cause or contribute to the occurrence of the explosion, fire or failure of gas supply.

The functions performed by TRC3B and the problems experienced with it are dealt with in Chapter 3. There can be no doubt that, as events transpired, the failure in the closed

position of the TRC3B temperature control valve contributed to the low temperatures and consequent high levels of condensate in Absorber B. This was not inevitable because appropriate manipulation of the bypass valve around the TRC3B control valve would have achieved effective temperature control in the bottom of Absorber B. However, the bypass valve was not appropriately manipulated during the period preceding the rupture of GP905. It is only in this indirect way that the failure to repair the TRC3B valve can be said to have contributed to the explosion and fire. In the circumstances, the priority given to the repair of the valve does not amount to evidence of a standard, practice or policy which caused or contributed to the accident.

On 25 September 1998 a number of paper charts in the control room of GP1 were not effectively recording the information which they were designed to record, either through lack of ink in the pens or through defective mechanism in their drive. In particular, the overhead flow from the ROD and the lean oil flow from GP1201 were not being recorded. In addition, the temperatures in the ROD/ROF area were not being recorded by temperature recorder TR1. Had the information which should have been, but was not, recorded, been available in the control room on 25 September 1998, it would have assisted in the analysis of the problem which arose on that day. Whether use would have been made of the information if it had been available does not appear from the evidence. It is, therefore, not possible to say whether the departure from proper maintenance standards, practices or policies with respect to these matters caused or contributed to the explosion, fire or failure of gas supply.

- **Asset management practices and policies**

Insofar as the failure to conduct the HAZOP study for GP1 and the reduction of supervision at Longford, including the transfer of engineers to Melbourne, were a result of Esso's desire to control its operating costs, asset management practices or policies may have been a contributing factor to the explosion, fire and failure of gas supply. However, it is not possible to establish any more direct causal link.

- **Risk management procedures and emergency procedures in force at the time of the occurrence**

The failure to conduct a HAZOP study for GP1 or to carry out any other adequate procedures for the identification of hazards in that plant has already been recognised as a contributing cause of the accident on 25 September 1998.



So far as emergency procedures are concerned, the emergency response on 25 September 1998 was, in all the circumstances, appropriate and effective. Shortcomings were identified but they were minor and did not affect the ultimate outcomes.

- **Any relevant changes in the standards, practices, and policies referred to in subparagraphs (b), (c), (d) and (e), which had taken place before the occurrence.**

As observed above, the reduction of supervision at Longford, including the transfer of engineers to Melbourne, may have contributed to the accident but it is not possible to establish a direct causal link.

- **The hydrate incident at the Longford facilities which occurred in June 1998, and any other previous incidents considered by the Commission to be relevant.**

The formation of hydrates in the slugcatchers in June 1998 was not a cause of, nor did it contribute to, the events which occurred in GP1 on 25 September 1998. However, the formation of hydrates has the potential to disrupt gas supply. This is dealt with below.

The cold temperature incident which occurred on 28 August 1998 made no direct contribution to the explosion, fire or failure of gas supply on 25 September 1998. However, the failure to report the incident deprived Esso of an opportunity to alert its employees to the effect of loss of lean oil flow and to instruct them in the proper procedures to be adopted in the event of such a loss. Had the incident been reported and appropriate action been taken after the report, the events of 25 September 1998 could have been averted.

- **Whether there was any breach of, or non-compliance with, the requirements of any relevant statute or regulation by Esso or BHP**

The causes of the accident on 25 September 1998 amounted to a failure to provide and maintain so far as was practicable a working environment that was safe and without risks to health. This constituted a breach or breaches of s.21 of the *Occupational Health and Safety Act 1985 (Vic)*.

### ***TERMS OF REFERENCE – CLAUSE 3***

- 15.8 Clause 3 of the Terms of Reference asks what steps should be taken by Esso or BHP to prevent or lessen the risk of: (a) a repetition of the incidents which occurred at the Longford

facilities on 25 September 1998; or (b) a further disruption of gas supply from those facilities.

15.9 GP1 does not now employ a lean oil absorption process as a means of producing sales gas. Whilst that situation continues, there can be no repetition of the events which occurred on 25 September 1998. However, were Esso to re-instate that process, all equipment used should be adequately protected against low temperature as a consequence of loss of lean oil circulation, either by the use of steels suitable for low temperatures or by adequate warning devices and shutdown systems. In addition, appropriate risk assessment procedures should be rigorously applied to any such re-instatement. With the plant operating as it does at the moment, there remains a need to review all ESD systems against current good engineering practice to ensure the effective isolation of the three gas plants from each other and the CSP. Esso should take that step.

15.10 The disruption to the supply of ethane continues and Esso should take steps to restore it to its pre-September 1998 level.

15.11 Otherwise, the steps to be taken by Esso are those involved in obtaining approval of a safety case or safety report. These are dealt with below under the heading "Recommendations."

15.12 BHP has no responsibilities, except in a financial sense, for the actual operation of the plants at Longford. The Commission does not, therefore, recommend any steps to be taken by BHP.

### ***RECOMMENDATIONS***

15.13 Apart from the specific steps above which the Commission considers that Esso should take, more general questions remain as to the future operation of Esso's facility at Longford, not only with regard to safety, but also with regard to the continuity of gas supply.

15.14 It is apparent that reliance upon OIMS to achieve a safe working environment in GP1 on 25 September 1998 was misplaced. The Commission is of the view that external obligations of a detailed and comprehensive kind (albeit identified by Esso itself) should be imposed upon Esso in order to avoid the repetition of an accident such as occurred on that day. Those obligations must be monitored to ensure that they are met and that aims similar to those expressed in OIMS are achieved in practice.

15.15 To this end, Esso should be required to evaluate the design of critical areas of its facility at Longford with a view to minimising the risk of a serious accident occurring. It should be required to develop an isolation philosophy and to examine its ESD system in order to

determine whether modifications, such as provision for the isolation of inventory within particular areas of each plant or the capacity to depressurise isolated sections of a plant, would avoid consequences of the kind experienced on 25 September 1998. Esso should be required to assess the safety limits of the metal used in vessels and pipes having regard to the possibility of operating temperatures above or below design limits.

- 15.16 Esso should also be required to demonstrate that its operating standards, practices and policies are periodically reviewed and that the documentation of each identified procedure includes an explanation of the potential hazards associated with the procedure. The critical procedures include start up, controlled shutdown, emergency shutdown and any deviation from normal operating conditions.
- 15.17 Of central importance is the training by Esso of its employees. An obligation should be imposed upon Esso to demonstrate that its training programmes and techniques impart knowledge of all identifiable hazards and the procedures required to deal with them. Not only should Esso be required to demonstrate that the necessary knowledge is imparted, but also that it is retained for use in an emergency. Esso should be required to show that written procedures are readily available to operators to enable them to respond to deviations from normal process conditions and that its management systems are expressed in a readily understandable form. Esso should also have to identify an incident reporting procedure, not only for injury to personnel or damage to plant, but for process upsets of a significant kind.
- 15.18 Finally, Esso should be required to show that plant operations are monitored and operating practices are overseen at an appropriate level. This would require an assurance that access to sufficient engineering, operating and maintenance skills would be available on site at all times and that there would be regular and comprehensive surveillance of operating practices, using properly kept records as well as day to day observations.
- 15.19 The means by which these and other requirements to ensure the safe operation of the facility at Longford might be met is to be found in the safety case or safety report procedure already referred to in Chapter 14. Under that procedure a safety case or report prepared by the operator of a major hazard facility, such as Esso, must be accepted by the relevant authority as a prerequisite to the operation of the facility. Failure to comply with the safety case would be an offence.
- 15.20 A safety case of the type suggested would contain an identification of all hazards having the potential to cause a serious accident, a detailed and systematic assessment of risk, a specification of the steps taken to minimise the likelihood of an accident and a description of

the design and layout of equipment, including the use of protective devices to ensure the reduction of risk so far as is reasonably practicable. The identification of hazards would be required to be continual and the safety case would specify the requisite inspection, maintenance and testing programmes.

- 15.21 The safety case would identify systems for monitoring, auditing and reviewing the implementation of its safety policies, procedures and performance standards and would identify all standards, Australian and international, to be applied in the design, construction, installation and operation of the facility or plant used in connection with the facility.
- 15.22 A safety case would also specify an office within the facility, the occupant of which would, while on duty, be responsible for the safe operation of the facility. It would require each employee working in the facility to be competent and to have the necessary skills, training and ability to undertake in both normal and abnormal conditions, including emergency conditions and during changes to the facility, the tasks allocated to that employee and to respond to conditions appropriately.
- 15.23 A fire risk analysis would be contained in a safety case, together with a response plan for possible emergencies. The safety case would specify adequate procedures for shutting down or isolating, in the event of an emergency, each pipeline connected to or within the facility to stop the flow of hazardous materials through the pipeline. It would require the reporting of significant accidents and incidents.
- 15.24 An adequate safety case for Esso's facility at Longford would deal with the particular requirements of that facility and would address the problems disclosed by the events of 25 September 1998 and this inquiry.
- 15.25 Esso's facility at Longford is, however, not the only major hazard facility in Victoria and it would be inappropriate to confine the safety case procedure to a single onshore major hazard facility. A government authority would be required to administer such a procedure and its powers should extend to all major hazard facilities within the State.
- 15.26 For these reasons, the Commission recommends that a safety case or safety report procedure of the kind identified be extended by legislation to all major hazard facilities within the State and that a specialist agency, sufficiently independent of the VWA to avoid any conflict of interest, be established to administer that procedure
- 15.27 The safety case or safety report procedure deals with matters of safety. In so doing, it deals co-incidentally with most of the circumstances which would give rise to a failure of gas

supply. There are, however, some circumstances, such as those of the hydrate incident in June 1998, which do not pose a threat to safety but do pose a threat to supply. The Commission has given consideration to a means whereby an obligation might be imposed upon Esso to maintain the supply of gas, in the same way as an obligation may be imposed upon it to maintain safety standards. However, in a situation where Esso is virtually the sole supplier of gas to Victoria, the imposition of such an external obligation would serve little practical purpose. Esso is aware of its responsibility to those who are dependant upon it for gas supplies. It is clearly within Esso's own interests, commercial and otherwise, to ensure the maintenance of supply. Moreover, the steps which have been, and are being, undertaken by Esso following the events of 25 September 1998 should, together with the implementation of the Gas Management System, be sufficient to enable it to maintain supply, provided those steps can be completed without delay.

# Appendix 1

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## THE FUNCTIONING OF THE COMMISSION

- A.1 On 12 October 1998 the Victorian Government announced its intention to establish a Royal Commission of Inquiry into the explosion and fire at Longford on 25 September 1998. Letters Patent were issued by His Excellency, the Governor of Victoria, on 20 October 1998 appointing the Honourable Sir Daryl Michael Dawson AC, KBE, CB and Mr Brian John Brooks BE, FIEAust, FAIP, FAIE, FIE as Commissioners and appointing Sir Daryl Dawson as Chairman. The Terms of Reference of the Commission are attached to the letter to His Excellency, the Governor, accompanying this Report. Attachment 1 to this Appendix lists significant dates in relation to the Commission.
- A.2 From the outset, the Victorian Government Solicitor made available a team headed by Mr Jonathan Smithers to provide legal services to the Commission and, by the time of its formal establishment, counsel to assist the Commission had already been engaged. They were Mr James Judd QC, Mr Simon Marks and Mr Ron Gipp. Mr Martin Grinberg was subsequently added as counsel assisting. Miss Jane Kennedy was appointed Secretary to the Commission and administrative support services were provided by the Department of Justice.

### ***PREMISES***

- A.3 It was apparent that a number of parties would be seeking leave to appear before the Commission and that premises large enough to accommodate them and their legal representatives would be required for the public hearings of the Commission. After consideration of a number of sites, two levels in the building at 360 Collins Street were selected and leased by the Department of Justice. The total space leased was 2,039m<sup>2</sup> comprising 1241m<sup>2</sup> on level 29 and 798m<sup>2</sup> on level 31. The location of the pillars on level 29 allowed for the speedy and simple construction of a hearing room with four entry points from the lift lobby. It was desirable from the point of view of security that the administration of the Commission be located on a different level from the hearing room and the space on level 31 enabled such an arrangement to be made. Very little adaptation on level 31 was required to make it suitable for the Commission's purposes.
- A.4 The premises at 360 Collins Street were selected on 27 October and by 14 December 1998 the necessary works had been completed to enable the Commission to commence

continuous public hearings. Tradesmen and technicians worked a considerable amount of overtime making alterations and installing cabling and equipment to enable the early commencement of hearings.

- A.5 The Supreme Court of Victoria had previously developed a purpose-built court room to accommodate a large trial known as the Estate Mortgage trial. After the completion of that trial the court room had been dismantled and the joinery work stored. The Supreme Court allowed the judge's bench, the associate's workstation and the witness box to be reassembled in the Commission's new premises, saving both expense and time.
- A.6 Adequate public seating was made available in both the hearing room and the open area adjoining the hearing room where proceedings could be viewed by means of closed circuit television. Representatives of the media, in particular, used this area which allowed them to move in and out more freely than they could from the hearing room. Three different views of the hearing room were taken by cameras in fixed positions in the hearing room and displayed on three monitors in this area.
- A.7 Large video monitors were installed at various locations in the hearing room to project documents referred to in the questioning of witnesses. A document camera in the witness box enabled the witness to point to a particular aspect of a document and, where necessary, to zoom in upon that aspect for a closer view. This proved to be of great use having regard to the many drawings and diagrams referred to during the Commission's hearings.
- A.8 Cabling was installed in the hearing room to enable the viewing of real time transcript. The parties provided their own monitors. Telephone lines and modems were also installed in the hearing room to enable the parties and their legal representatives to telephone or fax their offices. Usage of these phone lines was at the expense of the parties.
- A.9 The major parties were each allocated a meeting room on level 29. They were able to install such equipment as they required at their own expense. Accommodation was also allocated to the Victorian Government Reporting Service (VGRS).
- A.10 Office furniture and equipment was purchased, generally second-hand, in order to minimise the cost. Some items of equipment were leased for the duration of the Commission.
- A.11 At the conclusion of the public hearings on 15 April 1999, level 29 was no longer required by the Commission. However, the Supreme Court required a large court room for the hearings in the case of *Edinbay Pty Ltd & Ors -v- Aroni Coleman* and the Commission was able to make its hearing room available to the Court for that purpose, thus enabling a further

use to be made of these facilities with a consequent saving in cost. Arrangements were made for the Department of Justice to take over certain furniture and equipment used by the Commission upon the completion of the inquiry.

### ***TRANSCRIPT***

- A.12 Transcription services were provided by the VGRS and real time transcript was available to the Commission and those parties who chose to avail themselves of it. No charge was made for this service. Transcripts of the Commission's public hearings were also available through the VGRS's internet site. At the time of the Commission's Report, the number of hits upon the internet site was in excess of 20,000, indicating a significant interest in the Commission's hearings. The internet transcripts were viewed in locations as diverse as the USA, Norway, Singapore, Vietnam and New Zealand. A mechanism was installed to enable the internet feed to be switched off in the event that proceedings were required to be in camera. While no order was made for in camera proceedings, witnesses were ordered out of the hearing room. This order was deprived of much of its effectiveness when witnesses read the transcript of the proceedings, as some of them did, on the internet.
- A.13 At the end of each day the final and corrected version of the transcript for that day was entered on the internet. The day's proceedings could be downloaded on to personal computers and hard copies could be made.
- A.14 A computer programme known as Transcript Analyser was used by the Commission and counsel assisting the Commission. Co-ordinated by Ms Radhika Kanhai of the Victorian Government Solicitor's Office, it proved a useful tool in the locating and collation of the evidence contained in the 6,569 pages of transcript which the Commission's hearings generated.

### ***COMMUNICATIONS***

- A.15 A local computer network was installed for the Commission's use on and between levels 29 and 31. Existing cabling left by previous tenants was employed for the purpose. An internal electronic mail system was also created.
- A.16 The Commission's staff were assisted by the creation of an audio facility which enabled the proceedings in the hearing room on level 29 to be heard through computers in the Commission's offices on level 31. It enabled the lawyers and engineering experts to remain aware of what was occurring in the hearing room while continuing with their tasks upstairs.



## ***THE CORONER'S INVESTIGATION***

- A.17 The Victoria Fire Investigation Policy and Procedures, published by the Department of Justice in March 1998, established policies and procedures for the co-ordination of the various agencies with obligations or interests relating to the investigation of fires. The agencies were the Victoria Police, the Department of Conservation and Natural Resources, the Country Fire Authority, the Metropolitan Fire Brigade, the State Forensic Science Laboratories and, more recently, the Victorian Workcover Authority. There is a steering committee chaired by the State Coroner. Immediately following the explosion and fire at Longford on 25 September 1998, the Coroner established a task force to investigate the incident. Those involved were the Arson Squad from the Victoria Police, the Country Fire Authority and the Victorian Workcover Authority. The Arson Squad took the lead and the investigation was co-ordinated by Detective Senior Sergeant Hughes. Forensic experts were engaged, in particular, Professor Rhys Jones from the Department of Chemical Engineering at Monash University and Mr Robert Weiss from Orica Engineering Pty Ltd. Their roles were co-ordinated by Inspector Willis of the Victorian Forensic Science Centre. It was anticipated that the Coronial inquiry would take some six months before it was completed.
- A.18 The Coroner acted under his statutory powers to seize certain documents and critical equipment and to preserve the integrity of the site of the incident at Longford, including the control room of GP1.

## ***THE COMMISSION'S INVESTIGATION***

- A.19 Upon the establishment of the Commission, the Coroner suspended his investigation. The persons engaged in that investigation, including members of the Arson Squad, Professor Rhys Jones, Mr Robert Weiss and Mr Michael Connell from the Victorian Workcover Authority, joined the Commission's inquiry. There was a need for further expert advice concerning the gas production process and associated management issues and to meet that need the services of Det Norske Veritas (USA) Inc. (DNV) were engaged. DNV made available a number of experts led by Dr Gary Kenney and Mr Mark Boulton to advise the Commission during the course of its proceedings and in relation to its report. Dr Kenney had performed a similar role in inquiries in the United Kingdom, notably the Kings Cross inquiry and the Piper Alpha inquiry. The DNV team included Dr Robert Hutchison, Mr Stephen Robertson, Mr Michael Clarke, Mr Peter Telleson, Mr Henk Herfst and Ms Megan Brown. The Orica team assisting Mr Weiss included Mr Andrew Stewart, Mr Govind Mudaliar, Mr John Heath and Mr Peter McGowan. Amongst others engaged by the Victorian Government Solicitor were Professor Graham Richardson and Dr Graham Saville

of the Imperial College, London, to advise in relation to process simulation, Mr Rod Sylvester-Evans in relation to process issues, Professor Joe Matthews of Monash University in relation to fluid testing and vessel inspection, Metlabs, Amec Engineering Pty Ltd, the Commonwealth Defence Science and Technology Organisation in relation to metallurgical testing and Holmes Fire and Safety Pty Ltd together with Tyco Aust. Pty Ltd to advise in relation to fire-fighting systems. Additional engineers, Dr Luke Chippindall, Dr Belinda Mathers and Ms Mary Tomsic, were engaged by the Victorian Government Solicitor to provide technical assistance.

- A.20 Materials in the possession of the Coroner's task force, including witness statements and seized documents, were handed over by the Coroner to the Commission. Although the handover was made pursuant to a summons issued to the Coroner, it was facilitated by an amendment to the *Evidence Act* 1958 (Vic) which added s.19A. That section removed any impediment to the handover. At the same time another amendment was made to the *Evidence Act* by the addition of s.19D which provided that a witness should not be excused from answering a question or from producing a document upon the ground of legal professional privilege.

### ***APPLICATIONS FOR LEAVE TO APPEAR***

- A.21 Notices were placed in various newspapers on 4 November 1998 inviting applications for leave to appear before the Commission and announcing a preliminary hearing on 12 November 1998 to consider these applications. The Commission's premises at 360 Collins Street were not completed by 12 November and the preliminary hearing was held in Court Room 12 in the Supreme Court building. The Commission is indebted to the Supreme Court for its making the court room available. It was already fitted out for real time transcript and had a closed circuit television facility in an adjoining area so that proceedings could be relayed for the benefit of those who could not be fitted in the court room.
- A.22 17 applications for leave to appear were received by the Commission. Of these, three were not pursued on 12 November and were not granted. Of the 14 which were pursued on 12 November, one application was refused. The remainder were granted. The application which was refused was that of the Industrial Deaths Support and Advocacy group. Its interests fell outside the Terms of Reference. Attachment 2 is a list of the applications for leave to appear received by the Commission, indicating those applications which were granted.

## ***HEARINGS***

- A.23 The Commission's hearings were held over a period of four months and occupied 53 sitting days. The continuous hearings commenced on 14 December 1998 and continued until 23 December 1998 when they were adjourned for the Christmas break. It was intended that the hearings should resume on 4 January 1999, but the resumption date was adjourned to 11 January 1999 to allow the parties time to assimilate an initial core bundle of evidentiary material. The Commission sat continuously until 24 February 1999 when it adjourned to allow a review of the evidence and the preparation of further evidence. Hearings recommenced on 9 March 1999 and continued until 9 April 1999. On 15 April 1999 a final hearing took place to enable counsel assisting the Commission to make their final submissions. The parties were given until 26 April 1999 to file written final submissions. Esso was given until 3 May 1999 to file a written response to the other parties' final submissions.
- A.24 The Commission generally sat from 10.15 am to 12.45 pm and from 2.15 pm to 4.15 pm. However, during the later stages of the hearings, the hours were extended in order to hasten the conclusion of the proceedings. Initially, the Commission did not sit on Fridays in order to give time to counsel assisting the Commission to marshal the evidence to be adduced.
- A.25 Approximately 70 persons were in daily attendance before the Commission during the hearings. These included the parties, their legal representatives (including counsel assisting) and those instructing them. Attachment 3 contains a list of the thirteen parties appearing and their legal representatives.
- A.26 Sixty three witnesses were called to give evidence before the Commission. Some of these were recalled from time to time. A list of the witnesses appears in Attachment 4. Five hundred and ninety exhibits were tendered by the parties as indicated in the table below. One hundred of these were tendered subject to an order under s.19B(2) of the *Evidence Act* 1958, restricting publication to the parties and their legal representatives and then for the purposes of the Commission only.



*Exhibits tendered by parties*

Counsel assisting the Commission	368
Esso	201
Gascor/State of Victoria	10
Four unions	4
Trades Hall Council	4
Country Fire Authority	2
Workcover	1
<b>Total</b>	<b>590</b>

- A.27 222 persons were interviewed by members of the Victoria Police assisting the Commission. Some of these had already been interviewed by the police or the Victorian Workcover Authority when the Commission commenced its investigation.
- A.28 The Commission issued 92 summonses to produce documents, 74 of which were directed to Esso. It also issued a number of summonses to give evidence and produce documents. In response, the Commission received some 175,000 pages of documents, approximately 120,000 of which came from Esso. The documents filled approximately 650 lever arch files occupying 13 five-shelf storage cabinets.
- A.29 Esso did not produce a list of relevant documents enabling the Commission to identify precisely the material which it sought. This meant that the Commission had to seek a mass of documentation by summons in order to determine what was relevant. It often took some weeks for documents to be produced in response to summonses and when the material was produced it often did not contain the information sought.
- A.30 As a result, a series of informal document meetings was instituted on 2 February 1999. At these meetings, experts from Esso and the Commission, in the presence of lawyers from both sides, discussed and explained the requests for documents and other information. These meetings did enable some documents with a high priority to be identified and obtained more quickly.

***WRITTEN SUBMISSIONS***

- A.31 Twenty-six written submissions were received by the Commission from the public. A number of those submissions were from people who had worked in gas plants or similar industries while others were from people making suggestions or expressing their views about the inquiry and matters pertaining to the terms of reference. These submissions are listed in Attachment 5.

## ***DOCUMENT MANAGEMENT***

- A.32 In November 1998, the Victorian Government Solicitor co-ordinated discussions amongst solicitors for the major parties participating in the Commission's proceedings about the use of an electronic document management system. A document management protocol was agreed, based upon a common document numbering ("barcode") system. This was managed by Ms Beth Allatt of the Victorian Government Solicitor's Office. The system was also designed to allow the use of electronic images of documents. Images were provided promptly by BHP and the State of Victoria. Ultimately, Esso also produced over 90% of its documents in electronic form. Unfortunately, this was not done in sufficient time for them to be used in that form to any significant degree. The first batch of electronic information was produced by Esso on 18 January 1999, 11 weeks after the first hard copies had been produced. The provision of electronic information never caught up with the provision of hard copy so that hard copy was used throughout the hearings. Nor was the technological capacity to distribute exhibits in electronic form used so as to avoid the need for photocopying. Generally, documents which were tendered had to be photocopied hurriedly by the Commission's staff and distributed to enable cross examination to take place without delay. Thus, the Commission's hearings were "paper", rather than electronic hearings, and did not make the best use of technology to reduce the volume of paper employed.

## ***LEGAL PROFESSIONAL PRIVILEGE***

- A.33 On 21 December 1998, counsel for Esso sought to raise legal professional privilege in objecting to a question asked by counsel assisting the Commission of a witness who was in the witness box. The witness was legal counsel employed by Esso. Counsel assisting the Commission placed reliance upon s.19D of the *Evidence Act* in answering the objection. Counsel for Esso then indicated that Esso wished to test the validity of s.19D in the Federal Court of Australia. The witness was stood down to enable Esso to take that course. Proceedings (VG733 of 1998) were commenced in the Federal Court on 23 December 1998 against the Commissioners and the State of Victoria. A case was stated for the consideration of a full court raising the question whether s.19D was a valid law of the Victorian Parliament. The matter was argued on 10 February 1999 and judgment was delivered on 1 April 1999. The Court (Black CJ, Sundberg and Finkelstein JJ) upheld the validity of s.19D. Esso commenced proceedings in the High Court of Australia seeking special leave to appeal against the judgment of the Federal Court.
- A.34 In the meantime the Commission's hearings were nearing completion and the question which had raised the issue of the validity of s.19D no longer required an answer for the

Commission to be able to conclude its inquiry. Had Esso not sought to test the validity of s.19D, the Commission's proceedings may have been shortened to some extent, but, in the end, it was not necessary to pursue the question which gave rise to the Federal Court proceedings.

*Attachment 1. Chronology of significant dates*

25 September 1998	An explosion and fire occurred at the Longford Plant, killing Peter Wilson and John Lowery, injuring eight people and resulting in the cessation of all gas supply from the Longford facilities.
12 October 1998	A Royal Commission was announced to inquire into the fire and explosion at the Longford Plant.
20 October 1998	Terms of reference of the Royal Commission were entered in the Register of Patents Book No.41 Page 166. Terms of Reference of the Commission were published in a special edition of the Victoria Government Gazette.
27 October 1998	Suitable accommodation for the Commission was selected.
4 November 1999	A notice appeared in various newspapers to: announce the date of the Commission's preliminary hearing; outline the procedure for lodging written applications for leave to appear before the Commission; and invite general written submissions.
6 November 1998	The first subpoena was issued by the Commission for the production of documents.
12 November 1998	A preliminary hearing was conducted to consider applications for leave to appear (venue: Court 12 of the Supreme Court of Victoria)
17 November 1998	A number of Commission staff moved in to 31/360 Collins Street (all initial staff had moved in by 14 December).
14 December 1998	Continuous hearings commenced in the Commission's hearing room located at 29/360 Collins Street.
23 December 1998	The Commission's continuous hearings were adjourned for Christmas.
23 December 1998	<i>Federal Court action:</i> Esso commenced proceedings in the Federal Court of Australia to challenge the validity of S19D of the <i>Evidence Act 1958 (Vic)</i> (which gives a Royal Commission power to override legal professional privilege).
11 January 1999	Continuous hearings resumed.
27 January 1999	Application was made by the Trades Hall Council to extend the terms of reference of the Commission.
1 February 1998	Application by the Trades Hall Council to extend the terms of reference was refused.
9 February 1999	The date for completion of the Commission's report was extended to 30 June 1999 by order of the Governor. This order was entered in the Register of Patents Book No.41 Page 183.
10 February 1999	<i>Federal Court action:</i> Hearing conducted. Judgement reserved.
24 February 1999	Continuous hearings were adjourned to a date to be fixed to enable the preparation of expert testimony and for the parties to review material.
9 March 1999	Continuous hearings were resumed.
1 April 1999	<i>Federal Court action:</i> Decision handed down – validity of s.19D was upheld.
1 April 1999	<i>Federal Court action:</i> Esso lodged an application for special leave to appeal to the High Court.
9 April 1999	Continuous hearings were completed.
15 April 1999	Final submissions by counsel assisting the Commission.
26 April 1999	Final written submissions received from parties.
3 May 1999	Replies submitted by some parties.

*Attachment 2. Applications for leave to appear*

<b>Date received</b>	<b>Application by:</b>	<b>On Behalf of:</b>	<b>Notes</b>
9/11/98	Mallesons Stephen Jaques	BHP	Application granted
10/11/98	Middletons Moore & Bevins	Esso	Application granted
10/11/98	Arnold Bloch Leibler	Victoria Workcover Authority	Application granted
10/11/98	Gavan J. Burns	Executrix and family of Peter Wilson and the executrix of John Lowery (the persons killed in the explosion).	Application granted
10/11/98	Sullivan Braham Pty	The daughters of John Lowery (killed in the explosion)	Application granted
10/11/98	Maurice Blackburn & Co	Four unions which represent the entire workforce at Longford whose members were killed or injured (Australian Workers Union; Australian Manufacturing Workers Union; the Communications, Electrical, Electronic Machinery, Postal, Plumbing and Allied Services Union of Australia and the Australian Services Union).	Application granted
10/11/98	David Grace Q.C.	Industrial Deaths Support & Advocacy	Application refused
10/11/98	Freehill Hollingdale & Page	The State of Victoria (including relevant departments, agencies or authorities); and Gascor (including respective subsidiary and/or associated companies as applicable)	Application granted
10/11/98	Huntsman	Huntsman Chemical Company Australia Ltd	Application granted
10/11/98	Cornwall Stodart	Kemcor Olefins P/L & Subsidiaries	Application granted
10/11/98	Victorian Trades Hall Council	Affiliated union organisations: United Firefighters Union & Community and Public Sector Union, and Building Industry Group of Unions	Application granted
10/11/98	Maddock Lonie & Chisholm	Country Fire Authority	Application granted
10/11/98	Howie & Maher	Leader of opposition in the State of Victoria - Mr John Brumby Shadow Minister for Workcover – Mr Theo Theophanis Shadow Minister for Minerals & Energy - Mr Peter Loney	Application granted
10/11/98	Phillips Fox	Insurance Council of Australia Ltd	Application granted
10/11/98	Australian Society of CPAs	Australian Society of CPAs	No appearance
10/11/98	Shayne Keenan	Shayne Keenan	No appearance
11/11/98	Diane Anderson	Tooronga ALP	No appearance



**Attachment 3. Parties with leave to appear before the Commission**

<b>Party</b>	<b>Solicitor</b>	<b>Counsel</b>
Counsel assisting the Commission	Victorian Government Solicitor's Office	James Judd QC Simon Marks Ron Gipp Martin Grinberg
BHP	Mallesons Stephen Jaques	Neil Young QC Charles Scerri QC Nemeer Mukhtar
Esso	Middletons Moore & Bevins	John Middleton QC Malcolm Titshall QC Michael Hennessy Tony Kelly Peter Booth Tim Walker Greg Harris
The Victorian Workcover Authority	Arnold Bloch Leibler	Robert Richter QC Neil Clelland
Executrix and Family of Peter Wilson and the executrix of John Lowery	Robert Smart & Assoc Pty Ltd	Gavan J. Burns
Daughters of John Lowery	Sullivan Braham Pty	David O'Doherty
AWU, AMWU, CEPU, ASU (Workforce unions at Longford facilities)	Maurice Blackburn & Co	Paul Scanlon
State of Victoria and Gascor	Freehill Hollingdale & Page	Alan Archibald QC Geoffrey Nettle QC Jonathan B.R. Beach Stewart Anderson
Huntsman Chemical Company Australia Pty Ltd	Norton Smith and Co	Paul Anastassiou
Kemcor Olefins P/L & Subsidiaries	Cornwall Stodart	Peter Bick QC
Affiliated union organisations United Firefighters Union & Community and Public Sector Union Victorian Trades Hall Council (Leigh Hubbard)	Sary George & Myall	Mark E. Dean Rachel Doyle
Country Fire Authority	Maddock Lonie & Chisholm	Andrew Kirkham QC Mark Henry Brian Walters
Leader of opposition in the State of Victoria - Mr John Brumby Shadow Minister for Workcover - Mr Theo Theophanis Shadow Minister for Minerals & Energy - Mr Peter Loney	Howie & Maher	Stuart Morris QC Greg Wicks Mark Dreyfus Damien Murphy Gregory Meese
Insurance Council of Australia Ltd	Phillips Fox	Ross H. Gillies QC Geoff G. McArthur

**Attachment 4. Sequential list of witnesses called**

<b>No.</b>	<b>Witness</b>	<b>Position</b>	<b>Date Examined</b>
1	OLSEN Robert Courtney	Chairman & Managing Director Esso Australia Ltd	16 Dec 98
2	VANDERSTEEN Shane	Maintenance Fitter, Longford Plant	16 Dec 98
3	MILLER Robert	Operations Technician 2, Longford Plant	17 Dec 98
4	WATSON Jason	Trainee Operations Technician, Longford Plant	17 Dec 98
5	GALLAGHER Martin	Process Technician 2, Longford Plant	17 Dec 98
6	SHERRY David	Operations Manager, CFA	17 Dec 98
7	HARRISON William	Longford Winter 1999 Gas Projects Manager, Longford Plant (Engineer)	21 Dec 98
8	WORRALL Denis	Counsel for Esso	21 Dec 98
9	JONES Mark	Officer of the CFA	22 Dec 98
10	JOYCE Laurence	Acting General Manager, Worley ABB	22 Dec 98
11	BENNETT Stephen	Process Technician 2, Longford Plant	22 Dec 98
12	CUMMING Grant	Operator in the Control Room Rotation, Longford Plant	23 Dec 98
13	FOSTER Gregory	Technician 1 Operator, Longford Plant	12 Jan 99
14	BORTHWICK Darren	Sheet metal worker, Longford Plant (contractor)	12 Jan 99
15	DELAHUNTY David	Control Room Operator, Longford Plant	13 Jan 99
16	ANDERSON Robert	Operations Technician 2, Longford Plant	13 Jan 99
17	KNIGHT Andrew	Mechanical Fitter with Workhire (contractor)	13 Jan 99
18	RICKERBY Robin	Control Room Operator, Longford Plant	13 Jan 99
19	JACKSON Martin	Trainee Operations Technician, Longford Plant	13 Jan 99
20	ELLIOT Robert	Technician 2 Panel Operator, Longford Plant	13 Jan 99
21	NOBLE Andrew	Plant Supervisor, Longford Plant	18 Jan 99
22	GIBBS Michael	Control Room Operator, Longford Plant	18 Jan 99
23	SMITH David	Tech 2 Operator Technician, Longford Plant	19 Jan 99
24	NADEBAUM Richard	Process Technician Level Two, Longford Plant	19 Jan 99
25	WEISS Robert	Senior Consultant, Orica Engineering Pty Ltd	19 Jan 99 & 21 Jan 99
26	MUNN Rodney	Operations Integrity Group Safety Co- ordinator, Longford Plant	21 Jan 99
27	YOUNG Peter	Training Officer employed by South East Australian Training Services (division of the East Gippsland Institute of TAFE)	21 Jan 99
28	OWEN Richard	Manager responsible for engineering for Gas Plant 1 restart, (previously Technical Director – Offshore)	21 Jan 99
29	TOBEN Paul	Offshore Operations Superintendant	21 Jan 99
See 19 Jan	WEISS Robert	Senior Consultant, Orica Engineering Pty Ltd	27 Jan 99
30	BURLEY Peter	Operations Technician 2, Longford Plant	27 Jan 99
31	JONES Professor Rhys	Professor of Mechanical Engineering at Monash University	27 Jan 99
32	HOGAN Peter	Operations Technician Level 2, Longford Plant	28 Jan 99

No.	Witness	Position	Date Examined
33	WATTS David	Plant Operator – Esso	28 Jan 99
See 19 Jan	WEISS Robert	Senior Consultant, Orica Engineering Pty Ltd	28 Jan 99
34	WILSON Ray	Plant Supervisor, Longford Plant	1 Feb 99
35	ROBINSON Noel	Operation Technician, Compressor Rotation, Longford Plant	2 Feb 99
36	McFARLANE Peter	Process Technician 2, Longford Plant	3 Feb 99
37	OLSSON Wayne	Control Room Operator, Longford Plant	3 Feb 99
38	WIJGERS Johannes	Plant Supervisor, Longford Plant	3 Feb 99
39	RAWSON Ronald	Operations Technician Level 2, Longford Plant	4 Feb 99
40	SHEPARD Michael	Production Co-ordinator, Crude and Power Generation, Longford Plant	9 Feb 99
41	WARD James	Control Room Operator, Longford Plant	11 Feb 99
42	ROBINSON Bruce	Mechanical Technician 2, Longford Plant	16 Feb 99
43	KENNEDY Ian	Relief Plant Supervisor, Longford Plant	16 Feb 99
44	VISSER William	Plant Supervisor, Longford Plant	17 Feb 99
45	HECTOR William	Technician Two Operator, Longford Plant	22 Feb 99
46	LEE Mark	Maintenance Supervisor, Longford Plant	24 Feb 99
47	KEADY Patrick	Mechanical Maintenance Supervisor, Longford Plant	24 Feb 99
48	SARGENT Glenn	Project Manager, Infrastructure Development, VWA	9 Mar 99
49	SUNDERLAND Phillip	Maintenance and Reliability Supervisor for Esso Norge A/S (Norway) on assignment from Esso Australia Ltd	9 Mar 99
50	LEA David	Executive Director Minerals and Petroleum Division, Department of Natural Resources and Environment	10 Mar 99
51	COLEMAN Peter	Operations Manager, Esso Australia	10 Mar 99
52	SHINNERS Christopher	Production Technology Manager, Esso Australia	16 Mar 99
See 17 Dec	SHERRY David	Operations Manager – CFA	17 Mar 99
53	MUSGRAVE Luke	Gas Plant Restart Manager, Longford Plant	22 Mar 99
54	DASHWOOD John	Special Projects Manager, Longford Plant	24 Mar 99
See 21 Dec	HARRISON William	Longford Winter 1999 Gas Projects Manager, Longford Plant	24 Mar 99
55	SIKKEL Mark	Director of Esso Australia Ltd (EAL) and Esso Australia Resources Ltd (EARL)	25 Mar 99
See 16 Dec	OLSEN Robert	Chairman and Managing Director of Esso Australia Ltd (EAL) and Esso Australia Resources Ltd (EARL)	26 Mar 99
See 21 Jan	YOUNG Peter	Training Officer employed by South East Australian Training Services (a division of the East Gippsland Institute of TAFE)	29 Mar 99
56	KENNEY Dr Gary	President, Det Norske Veritas -USA, Inc	29 Mar 99
57	SYMES Peter	Gas Management System Implementation Team Leader, Esso Australia Ltd.	30 Mar 99
See 27 Jan	RHYS-JONES Professor	Professor of Mechanical Engineering, Monash University	30 Mar 99
See 29 Mar	KENNEY Dr Gary	President, Det Norske Veritas -USA, Inc	30 Mar 99
See 19 Jan	WEISS Robert	Senior Consultant, Orica Engineering Pty Ltd	30 Mar 99

<b>No.</b>	<b>Witness</b>	<b>Position</b>	<b>Date Examined</b>
58	KEEN Gordon Robert	Supervisor, Recovery Enhancement Projects Group, Esso Australia Ltd	31 Mar 99
59	REINTEN Ronald	Planning Supervisor for Esso Australia Ltd (EAL)	6 Apr 99
See 29 Mar	KENNEY Dr Gary	President, Det Norske Veritas -USA, Inc	6 Apr 99
60	HOPKINS Dr Andrew	Senior Lecturer in Sociology, the Australian National University	7 Apr 99
61	BAKER Kenneth	Vice President of Baker & O'Brien, Inc	8 Apr 99
62	COLLINS Charles	President, Barnes and Click, Inc	9 Apr 99
63	STICKLES Dr Raymond	Principal specialising in Process Safety and Risk Management consulting	9 Apr 99

**Attachment 5. General submissions received by the Commission**

<b>No.</b>	<b>Date received</b>	<b>From</b>
1	6/11/98	John Clark <i>Former Group General Manager of BHP Engineering (1989-1995).</i>
2	9/11/98	L.S. Black
3	10/11/98	Austherm Pty Ltd
4	10/11/98	Peter Horan
5	10/11/98	Diane Anderson <i>Tooronga Branch of ALP</i>
6	10/11/98	A. Jamieson <i>Woodside Energy Ltd (NWSV)</i>
7	11/11/98	Merv Wilson <i>RAWDEEAL (Residents Against Waarre Development Endangering Environment And Landuse)</i>
8	13/11/98	John Shaw <i>Former General Manager of Gas &amp; Fuel Corp 1981 - 1988</i>
9	17/11/98	David Healy <i>Ex employee of Esso-BHP offshore oil facilities</i>
9A	25/11/98	John King <i>Retired chemical engineer</i>
10	1/12/98	Shayne Keenan
11	1/12/98	Geoff Peverell <i>Ex employee of Gas &amp; Fuel Corp.</i>
12	4/12/98	Bob Douglas
13	8/12/98	Anonymous Esso employee
14	21/12/98	John King <i>Retired chemical engineer</i>
15	24/12/98	John Bottomley <i>Urban Ministry Network</i>
16	13/1/99	John King <i>Retired chemical engineer</i>
17	21/1/99	Dr Wayne Chamley <i>Ex-employee of Department of Natural Resources and Environment</i>
18	25/1/99	Alex Morozow <i>Offshore Safety Section, Petroleum Division, Department of Industry, Science and Resources</i>
19	25/1/99	Howie & Maher <i>On behalf of the state opposition</i>
20	17/2/99	A.G Hopkins
21	21/12/98	Richard Casey
22	25/2/99	Dr Kenneth Byrne <i>Australian Institute of Forensic Psychology</i>
23	10/3/99	A.G Hopkins
24	22/3/99	John King <i>Retired chemical engineer</i>
25	19/4/99	Kelvin Thompson <i>Federal Member for Wills, Shadow Assistant Treasurer (former Victorian Shadow Minister for Energy &amp; Minerals)</i>
26	10/5/99	John King <i>Retired chemical engineer</i>

# Appendix 2

## GPI ISOLATIONS TO GAS PLANT PROCESS

P&ID	Description	Valve	Service	Comments
250-12692	GPI Propane Refrigerant Accum.	Isolate valve to Propane to Chiller GP902A Isolate valve to Propane to Chiller GP902B Isolate the makeup Propane to GP2 Regeneration System	Liquid	Isolate – low press Isolated – low press Isolated – low press Isolated
250-12682	Vapour from GP2 Feed Liquid Strip	Isolate UV H109 located at GPI Inlet Station	Vapour	Isolated
250-12625	GPI to GP2 Hot Oil from Storage	Isolate block valve to SNA depress line Isolate from GP2 hot oil surge drum GT1118	Vapour Hot Oil	Isolated Isolated
250-12593	GPI/GP2 Regeneration Tie Line	Isolate inlet/outlet from GP1102D Treated Gas from GPI MOL Sieve- block valve d/s FVG107 & bypass	Gas Gas	Isolated Isolated
250-12512	GPI Inlet Separator GPI1101 – Inlet Isolations	MLA S/C isolation valve inlet to GPI1101 BTA S/C isolation inlet to GPI1101 Isolate GPI emergency fuel gas makeup Isolate regen. gas comp. GP305A/B/C from inlet to GPI1101 Isolate block valve from GPI regen. gas scrubbers	Gas Gas Gas Gas Gas	Isolated Isolated Isolated Isolated Isolated
250-12584	Regen. Gas to GPI/GP2 Tie	Isolate block valve from GPI regen. gas scrubbers	Gas	Isolated
250-12570	Isolate GPI LPG Shipping Pump Discharge Header	Isolate u/s of FY 153 and bypass Isolate u/s of FY 152 and bypass Isolate block valve u/s of FT G152 Isolate block valve u/s of FT G153 Isolate block valve to LPG booster pumps	LPG LPG LPG LPG LPG	Isolated Isolated Not reqd. second block further u/s - 205-12571 Not reqd. second block further u/s - 205-12572 Not reqd. second block further u/s - 205-12573
250-12510	GPI Inlet Control Valves	Isolate ESD 502.2 MLA Slugcatcher Inlet Isolate ESD 502.1 BTA Slugcatcher Inlet	Gas Gas	Isolated Isolated

P&ID	Description	Valve	Service	Comments
		Residue Gas from GP2 Sales Gas Header – - MLA Inlet to GP1 - BTA Inlet to GP1	Gas Gas	Isolated Isolated
204-12508	GP1 Condensate from MLA Slugcatcher	- Block valve upstream of FIC 715 and bypass - ESD 160 and 161 - Block Valve upstream of LV LIC 705.B and bypass - Block valve u/s of FCV 714 and bypass - ESD 703A and ESD 703B	Liquid Liquid Liquid Liquid Liquid	Isolated – no bleed reqd. HP system Valve not shut ESD failed – startup team req this to open Isolated - no bleed reqd. HP system Isolated - no bleed reqd. HP system Isolated – no bleed reqd. HP system
204-12509	GP1 BTA/SNA Glycol Water Line	Isolate valve from K. O. drum pump GT1222	Liquid	Isolated needs to be reopened
204-12535	GP1/GP2 Inst. Air Tie	Isolate valve from GP1 recirc. system	Air	Isolated
255-12502	Water Dump GP2 Inlet Sep to Boot	- Block valves up/down of LV105 Plus two bypass block valves - Block Valve downstream of LV H103B Plus isolation to Boot (Block Valve)	Liquid Liquid Liquid Liquid	Isolated needs to be reopened-boot GP2 Isolated needs to be reopened-boot GP2 Isolated needs to be reopened-boot GP2 Isolated needs to be reopened-boot GP2
255-12503	GP2 S/C Filter Sep Water Dump GT1407	-Two Outlets from GT1407 downstream of LV H106A and LV H106B	Liquid Liquid	Isolated needs to be reopened-boot GP2 Isolated needs to be reopened-boot GP2
255-12516	Isolate Inlet to GP2 Demeth. GT-1112	- Isolate LVC9 upstream and bypass - Isolate block valve LVC9 and feed from GP2 expander	Liquid Liquid	Isolated – no bleed reqd. PSV protection Isolated – no bleed reqd. PSV protection
255-12518	Bypass to GP1 Product Debut.	- Isolate upstream of LVH131, bypass to GP1 Product Debut.	Liquid	Isolated and depressurised
255-12523	Startup Gas from GP1 to GT928 (Fuel Gas Header)	- Isolate line from sales gas - Isolate line from gas to knockout drum - Check CSC valve	Fuel Gas Fuel Gas Fuel Gas	Isolated Isolated Isolated
255-12524	Residue Gas from GP2 to GP1	- Isolate UV H105 - Isolate UV H105 and bypass	Gas Gas	Isolated Isolated
255-12525	GP2 Tie Line to Recycle Gas from GP1 Recompressors	- Close UV 108B - Block valves up/down FVH104 and bypass	Gas Gas	Isolated Isolated
255-12533	Outlet of GT1102 to GP1 Recompression	Isolate PV H128A (Block Valve) downstream and Block Valve Dia. 150 to Flare	Gas Gas	Isolated Isolated

P&ID	Description	Valve	Service	Comments
255-12534	Liquid Stripper GT924	L VH122 Downstream Isolation to GP1 Product Debut. Isolate bypass to GP1	Gas	Isolated
255-12539	Isolate LPG Condensers GT917	Isolate UV-128 from makeup line (GP1118A & B)	Gas	Isolated
255-12542	GP2 and GP3 Tie Line to Product Debut.	Isolate bleed to GT1128 u/s UV H128 Isolate ESD UV H124 Isolate inlet line from GP3 demeth. bottoms Isolate block valve to debut. feed preheater Isolate block valve from LPG product rerun pump 1213 Isolate u/s and d/s of FY H161 and bypass Isolate block u/s of FE H174	Gas Liquid Liquid Liquid Liquid Fuel Gas	Isolated Isolated (bleeddown from 258-12518) Isolated (bleeddown from 258-12518) Isolated and at low press Isolated and at low press Isolated and at low press Isolated
255-12560	Isolate Fuel Gas Heaters GT928			
255-12577	Flare K.O. Drum Transfer Pump	-Downstream Block Valve of GT1222 (not reqd. for GP1 isolation) -Block valve from returns of GNI222 (not reqd. for GP1 isolation)	Liquid Liquid	Isolated – need to be reopened for boot Isolated – need to be reopened for boot Pump driver needs to be re-instated
250-12571	LPG Shipping Pumps to LPG Pipeline	Isolate ROV G178	LPG	Isolated
250-12527	GP1 Residue Gas Scrubber to Residue Gas Sales	Isolate ESD 6 Block valve from fuel gas makeup to CSP Isolate block valve to meter run bypass	Gas Gas Gas	Isolated Isolated Isolated
204-12515	GP1 Residue Gas Scrubber to Residue Gas Sales	ESD 6A Isolate block valve to emergency bypass from S/C and emergency fuel gas to CSP	Gas Gas	Isolated Isolated
255-12530	Isolate Overflow from Dewatering Hydrocyclones	Isolate block valve d/s TEH 504	Water/Glycol	Isolated
250-12633	Isolate Condensate Overflow from Dewatering Hydrocyclones	Isolate block valve u/s PCB G135A going to GP2 feed liq stripper GT1102 Isolate block valve from secondary dewatering hydrocyclone to GP2 feed liq. stripper	Water/Glycol Water/Glycol	Isolated Isolated
258-12518	GP3 Demeth. Reboiler Outlet Products to CSP via GP2	Isolate block valves u/s and d/s of FV L294 and bypass	Liquid	Isolated – scaffold reqd. to bleed liq locked line not critic
255-12535	GP2 debut. feed	Isolate UV H127	Liquid	Isolated



P&ID	Description	Valve	Service	Comments
204-12512	bottoms to CSP GPI inlet separator GP1126 discharge isolations	Isolate block d/s of LVH 133 Isolate block valve on liquid overflow outlet Isolate block valves u/s and d/s of LCV 502 and bypass Isolate block valves u/s and d/s of LICV 502 A and bypass Isolate block valves u/s and d/s of LICV 502 B and bypass Isolate block valve from gas offtake to KVR suction scrubbers Isolate block valve from gas offtake to MLA inlet valve station Isolate block valve on gas takeoff to emergency bypass to GFC p/line Isolate block valve on gas takeoff to fuel gas to C-926 and CSP	Liquid Liquid Liquid Liquid Gas Gas Gas Gas	Isolated Isolated – normally isolated Isolated – normally isolated Isolated – normally isolated Isolated – normally isolated Isolated Isolated Isolated Isolated
250-12630	GPI water/condensate sep GP1125	Isolate 2 off block valves on outlet from vessel Isolate block valves u/s and d/s of LCV 501B and bypass Isolate block valves u/s of LCV501C and bypass Isolate block valves u/s and d/s of LCV 501A and bypass Isolate block valves u/s and d/s of PCVG 210 and bypass	Liquid Liquid Liquid Liquid Liquid	Isolated – normally isolated Isolated – normally isolated Isolated – normally isolated Isolated – normally isolated Isolated – normally isolated
250-12744	Isolate methanol transfer system from GPI	Isolate block valves on 50 mm line from methanol storage tank CS1306	Methanol	Isolated – thermal relief available



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# Glossary of Terms

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<b>Term</b>	<b>Description</b>
Absorber	A tower where the absorption process takes place. GP1 has two absorbers (A and B) which are equipped with valve cap trays that allow direct contact between inlet gas and absorption oil.
Absorption	A process whereby one or more components are removed from a gas by bringing the gas into contact with a liquid that has an affinity for the components to be removed.
Absorption Oil	See "Lean Oil".
Accumulators	A vessel that receives and temporarily stores a liquid.
Actuator	The part of a control valve that moves the valve plug. May be pneumatic, electric, hydraulic or gas powered.
Alarm	A warning device that advises the operator of an abnormal process condition, usually by sounding a horn and flashing a warning light.
Amine Switch Gear Building	The building in GP1 that contained the electrical switching equipment for the amine treating facilities.
Bailey system	The modern computer-based control system used to control the CSP, GP2 and GP3, as well as parts of GP1.
Barracouta	Referring to the Barracouta Gas Field, or related plant including the slugcatcher which primarily services the Barracouta field.
Battery Limits	The boundary limits of a defined plant unit – eg. the effective boundaries of GP1 within the Longford complex.
Block Valve	A valve used to isolate one section of a plant from another. A block valve is usually either fully open or fully closed and is not used to regulate flow.

Term	Description
Boiling Liquid Expanding Vapour Explosion	Commonly referred to as a BLEVE, this phenomenon occurs when a pressure vessel ruptures within a fire, and the released contents simultaneously vapourise and combust. The resultant explosion has enormous force.
Bottoms	Material removed from the bottom of a distillation column as a product stream.
Brittle Fracture	<p>A brittle fracture is defined as one that occurs without ductility or deformation. Characteristic features of a brittle fracture are:</p> <p>Fracture straight across the component section.</p> <p>Retention of original dimensions if a broken component is reassembled. An example is broken glass.</p> <p>Microscopic fracture features include cleavage (of metal grains) or an intergranular fracture path. In steels, a scanning electron microscope (SEM) is required to view such microscopic features.</p> <p>Tends to occur at lower temperatures, where deformation is inhibited or prevented.</p> <p>Tends to occur if component is restrained from moving or deforming under a load, i.e. a condition of high restraint. Typically, a well-braced, large or solid structure has more restraint.</p> <p>Tends to occur at higher strain rates, which do not allow the material time to deform. An extreme example of higher strain rate loading is impact loading, for example the impact of a hammer on an item.</p> <p>Less energy is required to fracture. Hence, where conditions are such that a component tends to fracture in a brittle manner, fracture tends to be more likely (easier) than if it were ductile.</p>
Butane	See Hydrocarbon

<b>Term</b>	<b>Description</b>
Bypass	<p>A pipe connection around a valve, regulator, or filter, which is opened to permit the passage of fluids while repairs or adjustments are being made to the valve, regulator, or filter.</p> <p>A pipe connection around a vessel that is partially or fully opened to control the amount of fluid that passes through the vessel.</p>
Cable Ladders	Support structures that carry cables around the plant.
Carry Over	The unintended flow of liquid through the vapour outlet of a processing vessel – eg. from the top of a distillation column.
Centrifugal Pump / Compressor	A type of pump or compressor that uses a rotating impeller to increase the pressure of a liquid or gas by centrifugal force.
Chiller	A heat exchanger which cools a fluid using a refrigerant (see refrigerant).
Condensate	<p>A light hydrocarbon liquid that is obtained by the condensation of hydrocarbon vapours. Condensate consists of varying amounts of propane, butane, pentane and heavier hydrocarbon fractions. It contains little if any methane or ethane, unless it is produced by chilling of the hydrocarbon vapour.</p> <p>Any vapour that has condensed into a liquid (e.g. steam condensate).</p>
Condenser	A heat exchanger in which the heat of vapours is transferred to a flow of air or other fluid, thereby causing all or a portion of the vapour to condense into a liquid. In the absorption system, a condenser is used to condense a large portion of the overhead vapours from the ROF.
Control Loop	A group of instruments that together control, indicate or record one process variable.
Control Valve	A valve that can be controlled automatically to regulate the flow through a pipe.

<b>Term</b>	<b>Description</b>
Controller	An instrument that maintains a process variable at a desired value known as the “setpoint”.
Cryogenic	A process or item of equipment which operates at very low temperatures (generally below -150°C). Now commonly applied to processes operating at temperatures well below 0°C.
CSP	The crude stabilisation plant at Longford, where liquids from the Bass Strait Oil Fields are initially processed before passing to the Long Island Point plant.
De-ethaniser	See demethanisation
Dehydration	A process whereby water vapour is removed from a gas. In a refrigerated absorption plant, inlet gas must be dehydrated before it can be processed. Otherwise, water vapour in the gas can freeze or form hydrates before the gas is cooled to the processing temperature of the absorber. Ice or hydrates can block trays and small diameter flow lines and cause hazardous pressures.
Dehydrator	An item of equipment designed to remove water from a stream.
Demethanisation	The process of removing methane from a process stream (demethanising). Similar processes to remove ethane and butane respectively are called de-ethanising / de-ethanisation and debutanising / debutanisation. Equipment items used for these processes are demethaniser / de-ethaniser and debutaniser.
Design Pressure, Design Temperature	These are the maximum pressure and temperature that a piece of process equipment is designed to withstand during operation.
Differential Pressure	The difference between two fluid pressures, such as would exist between two separate processes, or two parts of the same process (eg. the inlet and outlet of a heat exchanger).

<b>Term</b>	<b>Description</b>
Distillation	A heat dependent process that is used to separate one or more components (sometimes called fractions) from a substance that contains these components. In a lean oil absorption system, distillation is used to reject methane as well as recover heavier hydrocarbons from rich oil.
Distillation Column	A vertical pressure vessel used to separate the components of a fluid based on their boiling points.
Double block and bleed	A method of ensuring the complete isolation of vessels or pipework, using two block valves with a bleed valve open to atmosphere between them, thus ensuring that any leakage through either block valve is drained away.
Drum	A horizontal pressure vessel.
Ductility	A property of a material that allows it to undergo deformation without breaking.
Ductile Failure	<p>A ductile failure is defined as one that occurs with ductility or deformation. Characteristic features of a ductile failure are:</p> <p>Fracture at an angle to the component section, i.e. slanted or shear fracture.</p> <p>Original dimensions are irreversibly changed at the fracture. An example is chewing gum, stretched until it breaks.</p> <p>Microscopic fracture features include “dimples”, each dimple appearing like a miniature volcano containing a crater.</p> <p>Tends to occur at higher temperatures, where deformation is easier.</p>



<b>Term</b>	<b>Description</b>
	<p>Tends to occur if a component is not restrained from moving under a load, i.e. a condition of low restraint. Typically a component that is unbraced, small or of thin section has less restraint. Hence, as a fracture proceeds across a component section, there may be a tendency for the fracture features to change from brittle to ductile, as the remaining thickness of unbroken material diminishes. Whether it does or not depends on factors such as the material involved, temperature etc.</p>
	<p>Tends to occur at lower strain rates, which allow the material time to deform. Extreme examples of lower strain rate loading are “creep”, or sagging of a component over time.</p>
	<p>More energy is required to fracture. This can partly be understood as the creation of more fracture surface area, which requires more energy.</p>
Entrainment	<p>Carrying of small particles, droplets etc. in a flow of gas, particularly in relation to distillation.</p>
ESD System	<p>Emergency shutdown system – a system that allows operators to safely and rapidly shut down the plant in the event of an emergency.</p>
ESD valve	<p>Emergency shutdown valve – a fast operating valve (commonly of the gate type) which closes without allowing any leakage and is used to isolate equipment in emergency situations.</p>
Ethane	<p>See Hydrocarbon</p>
Feed Liquid Stripper	<p>A distillation column in Gas Plant 2 that strips methane and ethane out of condensate from the slugcatchers. Vapour from the Stripper flows to the KVR compressors in Gas Plant 1.</p>
Feedback Arm	<p>A lever connected to the stem of a control valve used to confirm the position of the stem (eg whether the stem is 35% open or 40% open).</p>

<b>Term</b>	<b>Description</b>
Fin-fan condenser/cooler	Air cooled heat exchangers where heat transfer is increased using fans to increase air circulation across tubes with fins to increase surface area.
Fireball	A fire, burning sufficiently rapidly for the burning mass to rise in the air as a cloud or ball.
Flash	Flashing is a crude distillation type separation used to provide a coarse separation of light and heavy components in a feed, often before feed to a distillation column.
Flash Tank	A two or three phase separator that operates at a lower pressure than upstream equipment. The resulting pressure drop that occurs as process liquids enter the flash tank causes lighter material in the liquid to vaporise or "flash" out of the liquid. In a lean oil absorption system, one or more flash tanks are used to recover methane vapours from rich oil.
Flooding	If there is excessive entrainment of liquids through trays or liquid back-up in the downcomers, a liquid level can build up above a distillation column tray. This is known as flooding and significantly reduces the effectiveness of the tower. This can also result in liquid and vapour leaving the column via the vapour discharge pipe.
Fluid	Any substance that can flow. This includes both liquids and gases but excludes solids.
Glycol	A liquid used to absorb moisture from natural gas and inhibit the formation of hydrates. (TEG, Triethylene glycol, MEG, mono ethylene glycol).
Handover	The process of information transfer between a staff member who has just completed a shift and the staff member taking over from him/her.
Heat Balance	Calculation to check the flow of heat energy into and out of a system.

Term	Description
Heat Exchanger	Equipment used to transfer heat between two streams via indirect contact (e.g. transfer of heat through a tube wall). Parts of a shell and tube type heat exchanger are the <i>tube bundle</i> (the surface through which heat exchange occurs), the <i>channel</i> (the section through which tube side material enters the tubes), the <i>tubesheet</i> (a plate separating the shell and tube sides). Material that passes through the tubes is said to be on the <i>tubeside</i> , while material outside the tubes but within the shell are on the <i>shellside</i> . Heat exchangers can be <i>cocurrent</i> (with material passing through both sides in the same direction) or <i>countercurrent</i> (with material passing through the sides in opposing directions).
Heavy/s	Higher molecular weight hydrocarbons (i.e. those containing a larger number of carbon atoms).
HI-GOR well	A well with a high ratio of gas to oil production. The HI-GOR wells in the Snapper field also produced large quantities of water, but this is not an inherent feature of a HI-GOR well.
Hydrate	A crystalline hydrocarbon and water compound, which forms under certain temperature and pressure conditions in gas processing and transmission facilities. Hydrates can accumulate in process equipment, thereby impeding fluid flow and causing hazardous pressure conditions.
Hydrocarbon	Any compound whose molecules are comprised solely of hydrogen (H) and carbon (C) atoms. Oil and natural gas are hydrocarbons. Common hydrocarbons found in natural gas include methane (CH <sub>4</sub> ), ethane (C <sub>2</sub> H <sub>6</sub> ), propane (C <sub>3</sub> H <sub>8</sub> ), butane (C <sub>4</sub> H <sub>10</sub> ), pentane (C <sub>5</sub> H <sub>12</sub> ) and hexane (C <sub>6</sub> H <sub>14</sub> ).
Hydrocyclone	A device used to separate liquids and gases, liquids and solids or liquids of differing densities using centrifugal force.
Hydrogen Sulphide (H <sub>2</sub> S)	A substance present in natural gas which must be removed before sale because of its toxic and other undesirable properties.

<b>Term</b>	<b>Description</b>
Jet fire	The combustion of material emerging with significant momentum from an orifice.
Kings Cross Piperack	A rack containing pipes transferring fluids between various equipment items throughout the Longford site which was located near GP922 and was affected by fire on the day of the incident.
KVRs	Compressors GP301B/C that are used to compress flash gas and send it back to the start of the process.
Lean Oil	Also called absorption oil.  A hydrocarbon liquid, similar to aviation kerosene, that is used as an absorbant to remove product-type hydrocarbons from natural gas.  Absorption oil that is essentially free of product-type hydrocarbons.
Light/s	Lower molecular weight hydrocarbons (i.e. those containing a small number of carbon atoms).
LPG	Liquefied Petroleum Gas, a hydrocarbon mixture consisting mostly of propane and butane. The raw LPG produced at Longford has a significant ethane fraction.
Marlin	Referring to the Marlin Gas Field, or related plant including the slugcatcher which primarily services the Marlin field.
McNeil Report	An internal Exxon report into the events on the 25 <sup>th</sup> September.
Methane	See Hydrocarbon
Molecular Sieve	A material containing very fine channels or cavities which “capture” a specific component, hence separating it out of a mixture of gases or liquids.
Monitor	A fixed position fire fighting nozzle used to spray water or foam on to a fire.
OIMS	Operations Integrity Management System

<b>Term</b>	<b>Description</b>
Open drain system	A system of pipework operating at atmospheric pressure for the safe disposal of liquids spilled or drained in the plant.
Overheads	Vapour flow off the top of a column.
Overheads	Material removed from the top of a distillation column as a product.
Overpressure	The pressure developed above atmospheric pressure at any stage or location in a pressure pulse (blast wave).
Pass	A valve “passes” when it does not close fully and some material flows through it when it is shut.
PDT	Portable Data Terminal, a handheld unit which is used in the field for recording information about plant operation before being downloaded to the SIDS computer system.
PIDAS	(Process Information Data Acquisition System) A computer based data system that collects and stores data from the Bailey system.
Pipebridge	A piperack that passes over a road or other passageway.
Piperack	The support on which a large number of pipes are carried through the plant.
Platform	Offshore Oil/Gas platform, where crude oil and/or natural gas are removed from sub-sea reservoirs and initial processing may take place.
Pneumatic Equipment/Recorders	Control equipment which is operated by compressed air.
Pool fire	The combustion of material evaporating from a layer of liquid at the base of the fire.
Positioner	A part of a control valve that amplifies the signal from a controller and causes the valve to move to a desired position.

<b>Term</b>	<b>Description</b>
Presaturated	The process of saturating lean oil with methane before using it in the absorbers. This is done to prevent the heating of the lean oil in the absorbers because of the absorption of methane.
Pressure Vessel	A tank designed to withstand pressure. Must comply with specific regulations.
Profs	Esso Australia's internal electronic mail system.
Propane	See Hydrocarbon
Raw Gas	Unprocessed natural gas.
Reboiler	A vessel, which uses direct (fired) or indirect heat exchange to add heat to process materials. In a lean oil absorption system, reboilers are used in rich oil demethanisation and lean oil distillation.
Reclaimer	An item of equipment similar to a distillation column, which is used at the Longford plant for removal of heavy components from lean oil before recycle to the lean oil system.
Recorder	An instrument that records the value of one or more process variables (typically two or three) as a graph on a paper chart.
Reflux	Liquid returned to a distillation column to improve the efficiency of separation of the feed components.
Refrigerant	A liquid, such as propane or freon, that boils at a very low temperature. Refrigerant is used to carry away heat that has been transferred to it by indirect contact with warmer process fluids in a shell and tube type heat exchanger called a chiller.
Refrigerated Plant	A type of plant which tends to operate at low temperature, typically -20 to -50 deg C. GP1 was a refrigerated lean oil absorption plant.
Release	The discharge of energy or of a hazardous substance from its containment system.

<b>Term</b>	<b>Description</b>
Residue Gas (Sales Gas)	Gas which has been stripped of heavier hydrocarbons or contaminant gases. The term is often used to describe the top product from an absorber or rich oil demethaniser. Residue gas is also called sales gas when it is metered for sales.
Rich Oil	Absorption oil that contains absorbed hydrocarbons.
Rich Oil Deethaniser (ROD)	A distillation tower that is used to remove ethane or methane (depending on the mode of operation) from rich absorption oil while retaining heavier hydrocarbons for later recovery.
Rich Oil Fractionator (ROF)	A distillation tower that is used to remove all of the absorbed light hydrocarbons remaining in the rich oil leaving the bottom of the ROD.
Rich Oil Trap Tray	One of the bottom trays in an absorber. All rich oil flowing down the absorber is “trapped” on this tray before leaving the absorber.
Roots	Colloquial term for the units on an indicator or recorder measuring flow using a square root scale.
Saturated	Containing the greatest amount possible of another substance.
Scrubber	A separator that is used to remove small amounts of liquid from a flowing gas stream. Scrubbers are installed downstream of absorbers to recover liquids that may be accidentally carried overhead along with residue gas. Scrubbers are also used to protect gas compressors from the hazardous effects of free liquids in inlet gas.
Seal Flush, Seal Oil	In order to optimise centrifugal pump operation, a mechanical seal can be used. <i>Seal oil</i> is used as a <i>seal flush</i> to lubricate and remove heat from the rotating mechanical seal.
Separator	Item of process equipment used to separate gas and liquid fractions.
Setpoint	The desired value of a process variable set by the operator on a controller.

<b>Term</b>	<b>Description</b>
Shell	See Heat Exchanger
SIDS	Surveillance Information Database System – the computer system used for manually collected data about plant operation.
Sight glass	A piece of equipment that allows visual observation of the level in a vessel
Slug	A large body of liquid that can accumulate in pipelines carrying both gas and liquids. These slugs periodically carry forward with the gas stream creating problems in handling the volume of liquid arriving at the delivery point. Slugcatchers, such as those at Longford, serve to ‘smooth out’ these slugs for a more constant flow into the plant.
Slugcatcher	A piece of equipment that has the purpose of receiving gas, condensate and water from pipelines, smoothing out the arrival of slugs, performing initial separations, and storing the liquids before they are processed.
Snapper	Referring to the Snapper Gas Field, or related plant.
Surge Tank	A vessel through which liquids or gases are passed to reduce flow or pressure surges.
Sweetening	Removing hydrogen sulphide and other sulphur compounds from natural gas.
Tag Number	The number given to a control loop.
Temporary Defeats Board	A board located in the Control room for the recording of protective devices which have been removed/bypassed, or which have failed.
Terms of Reference (ToR)	The scope of the Royal Commission and its authority to make conclusions and recommendations
Thermal Shock	Exposure to a sudden large change in temperature.



<b>Term</b>	<b>Description</b>
Toolbox Meeting	A meeting held at the beginning of each shift with operators and Shift supervisors in order to discuss work to be carried out during the shift and other matters.
Trap Tray	See Rich Oil Trap Tray
Trip	To automatically switch off as a result of operating conditions.
Tusks	Part of Longford's slugcatchers. The inlet gas and liquids enter the slug catcher barrels through relatively small, curved pipes known as tusks, which accelerate the mixture into the barrels.
Upset	A disturbance or abrupt change in the operating conditions of a vessel or column that results in unstable operation, the production of off-specification product or carry over of liquid.
Valve Positioner	See positioner
Valve Tray	A type of internal fitting used in process columns that can be operated at very low gas rates because of the ability of the valves to be closed.
Wobbe Index	An index of natural gas quality that defines its suitability for combustion in industrial and domestic equipment.
Work Order Request	A written request for maintenance or other work to be carried out on a piece of equipment.

# List of Abbreviations

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<b>Abbreviation</b>	<b>Description</b>
A	Alarm
API	American Petroleum Institute
AR	Analyser Recorder
BHP	BHP Petroleum (Bass Strait) Pty. Ltd.
°C	Degrees Celsius
CFA	Country Fire Authority
CFT	Critical Function Test
CMT	Crisis Management Team
COP	Critical Operating Parameter
CSP	Crude Stabilisation Plant
CV	Control Valve
d	Day
DCS	Distributed Control System
DP	Differential Pressure
DPAH	Differential Pressure Alarm High
DPR	Differential Pressure Recorder
EAL	Esso Australia Limited
ECI	Exxon Company International
ERP	Emergency Response Procedure

<b>Abbreviation</b>	<b>Description</b>
ESD	Emergency Shutdown
F	Flow
FC	Flow Controller
FCA	Field Change Approval
FI	Flow Indicator
FIC	Flow Indicator and Controller
FR	Flow Recorder
FRC	Flow Recorder and Controller
ft	Foot
G	Giga, prefix to units for $10^9$
GDP	Gross Domestic Product
GP1	Gas Plant 1
GP2	Gas Plant 2
GP3	Gas Plant 3
HAZOP	Hazard and Operability Study
HFA	High Flow Alarm
HFSD	High Flow Shutdown
HLA	High Level Alarm
HLSD	High Level Shutdown
HPA	High Pressure Alarm
HPSD	High Pressure Shutdown

<b>Abbreviation</b>	<b>Description</b>
hr	Hour
HS	Hand switch
HTA	High Temperature Alarm
HTSD	High Temperature Shutdown
I	Indicator
IC	Incident Controller
ICC	Incident Control Centre
IMT	Incident Management Team
J	Joules
k	Kilo, prefix to units for 10 <sup>3</sup>
kPa	Kilopascal
KVR	Compressors GP301B/C that are used to compress flash gas and send it back to the start of the process.
L	Level
l	Litre
LAN	Local Area Network
LC	Level Controller
LCV	Level Control Valve
LFA	Low Flow Alarm
LFSD	Low Flow Shutdown
LI	Level Indicator

<b>Abbreviation</b>	<b>Description</b>
LIC	Level Indicator Controller
LIP	Long Island Point
LLA	Low Level Alarm
LLR	Longford Liquid Recovery plant
LLSD	Low Level Shutdown
LPG	Liquefied Petroleum Gas
LR	Level Recorder
LRC	Level Recorder and Controller
LTA	Low Temperature Alarm
LTSD	Low Temperature Shutdown
LWMM	Longford Work Management Manual
M	Mega, prefix to units for 10 <sup>6</sup>
m	Metre
m <sup>3</sup>	Cubic Metre
MDMT	Minimum Design Metal Temperature
MDQ	Maximum Demand Quantity
MHF	Major Hazard Facilities
MHU	Major Hazards Unit
NC	Normally Closed
NNF	Normally No Flow
°F	Degrees Fahrenheit

<b>Abbreviation</b>	<b>Description</b>
OIMS	Operations Integrity Management System
OSG	Offshore Support Group
P	Pressure
P&ID	Piping and Instrumentation Diagram
PC	Pressure Controller
PDT	Portable Data Terminal
PIDAS	Process Information Data Acquisition System
PRA	Periodic Risk Assessment
PRC	Pressure Recorder and Controller
psi	Pounds per Square Inch
PSV	Pressure Safety Valve
QRA	Quantitative Risk Assessment
RAAF	Royal Australian Air Force
RAMS	Risk Assessment and Management System manual
RC	Recorder and Controller
ROD	Rich Oil Demethaniser (or Rich Oil De-ethaniser), Column GP1109 in GP1
ROF	Rich Oil Fractionator, Column GP1110 in GP1
sec	Second
SIDS	Surveillance Information Database System
SMM	Safety Management Manual

<b>Abbreviation</b>	<b>Description</b>
T	Temperature
T	Tera, prefix to units for 10 <sup>12</sup> .
t	Tonne
TC	Temperature Controller
TIC	Temperature Indicator and Controller
TPA	Transmission Pipelines Australia
TR	Temperature Recorder
TRC	Temperature Recorder and Controller
UV	Multipurpose Valve
VWA	Victorian WorkCover Authority

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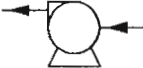
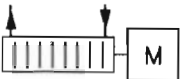
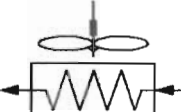
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# LEGEND

## INSTRUMENTS:

-  FIELD MOUNTED
-  PANEL MOUNTED
-  DISTRIBUTED CONTROL SYSTEM (*Computerised*)

## EQUIPMENT:

-  NON RETURN VALVE
-  OPEN VALVE
-  CLOSED VALVE
-  CONTROL VALVE (*Variable position*)
-  CONTROL VALVE (*Open / Close*)
-  USES LOWEST INPUT SIGNAL AS OUTPUT
-  HEAT EXCHANGER
-  SINGLE STAGE CENTRIFUGAL PUMP
-  MULTI STAGE CENTRIFUGAL PUMP
-  AIR COOLED HEAT EXCHANGER

\* VALVES CLOSED ON GP2 SHUT DOWN

† TYPICALLY FLOW TO EITHER GP919 OR TO GP2.

## ACRONYMS:

### LEVEL:

- LI Level Indicator
- LC Level Controller
- LR Level Recorder
- LIC Level Indicator Controller
- LRC Level Recorder Controller
- HLA High Level Alarm
- LLA Low Level Alarm
- HLSL High Level Shutdown
- LLSD Low Level Shutdown

### PRESSURE:

- PI Pressure Indicator
- PC Pressure Controller
- PR Pressure Recorder
- PIC Pressure Indicator Controller
- PRC Pressure Recorder Controller
- HPA High Pressure Alarm
- HPSD High Pressure Shutdown
- UV Multipurpose Valve
- DPAH Differential Pressure Alarm High
- DPR Differential Pressure Recorder

### OTHERS:

- AR Analytical Recorder
- ESD Emergency Shutdown
- NO Normally Open
- NC Normally Closed
- NNF Normally No Flow
- ROV Remote Operate Valve
- HS Hand Switch






### TEMPERATURE:

- TI Temperature Indicator
- TC Temperature Controller
- TR Temperature Recorder
- TIC Temperature Indicator Controller
- TRC Temperature Recorder Controller
- HTA High Temperature Alarm
- LTA Low Temperature Alarm
- HTSD High Temperature Shutdown
- LTSD Low Temperature Shutdown

### FLOW:

- FI Flow Indicator
- FC Flow Controller
- FR Flow Recorder
- FIC Flow Indicator Controller
- FRC Flow Recorder Controller
- HFA High Flow Alarm
- LFA Low Flow Alarm
- HFSD High Flow Shutdown
- LFSD Low Flow Shutdown

### STREAM COLOUR CODE:

-  NATURAL GAS
-  CONDENSATE
-  RICH OIL
-  LEAN OIL
-  LPG

# Appendix 3

## PROCESS FLOW DIAGRAM FOR GAS PLANT J & INTERCONNECTING UNITS

