IN THE PROVINCIAL COURT OF NEWFOUNDLAND

DISTRICT OF CLARENVILLE

IN THE MATTER OF THE PROVINCIAL OFFENCES ACT

S.N.L. 1995, Chapter F -31.1

AND IN THE MATTER OF

A Judicial Inquiry into the Causes and Circumstances surrounding an explosion and fire at the ***Come By Chance Refinery****, Come By Chance, Newfoundland and Labrador, occurring on March 25, 1998 which caused the deaths of Jerome Kieley and James Mercer.*

PRESIDING JUDGE . . . . The Honorable Patrick J. Kennedy, P.C.J.

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DATE OF REPORT: *August 8, 2005*

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INTRODUCTION

The following is a report into the causes and the circumstances surrounding the deaths of Jerome Kieley and James Mercer on heater 1401 at the Come-by-Chance Refinery, operated by North Atlantic Refining Limited, at Come-by-Chance, Newfoundland and Labrador, March 25th, 1998.

MANDATE OF THE INQUIRY

On October 7th, 2000, the Minister of Justice and Attorney General directed the Chief Judge of the Provincial Court to arrange for an Inquiry into the cause and circumstances surrounding the death of Jerome Kieley and James Mercer. The Inquiry was called under the auspices of the Fatal Investigations Act, S.N.L. 1995, Chapter F, 6-1 as amended, and was held under the procedures set out in the Provincial Offences Act S.N.L., 1995, Chapter P. 31 as amended. The Inquiry was not called for the specific purpose of ascertaining the cause and origin of the fire that caused the deaths, however, any proper inquiry into the cause of death necessitates consideration of the background and cause of the fire in heater 1401 on March 25th, 1998. The Inquiry in this case was called under s. 42 and 43 of the Provincial Offences Act. The Inquiry was held in public. It first convened on April 30th, 2001, at which time standing was granted to North Atlantic Refining Limited, Province of Newfoundland and Labrador, Department of Government Services and Lands, the Department of Environment and Labour, the United Steelworkers of America, Mrs. Mercer and Mrs. Kieley.

An Inquiry under the Provincial Offences Act is a fact-finding hearing. It is not a trial, and under s.49.3 of the Provincial Offences Act the hearing Judge is precluded from making findings of legal responsibility (i.e., fault) or conclusions of law. This report makes no conclusions as to civil or criminal liability of any party(s). The presiding Judge, at the conclusion of the Inquiry, is required to make a written report to the Attorney General which should contain findings as to the following:

a. the identity of the deceased,

b. the date, time and place of death or the fire,

c. the circumstance under which the death or fire occurred,

d. the cause of death or the fire, and

e. the manner of death.

The presiding Judge at the Inquiry is also given the discretion to make recommendations that will contribute to the prevention of similar deaths or fires in the future.

BACKGROUND

The Come-by-Chance Refinery was designed and built by Procon (Great Britain), a former subsidiary of UOP (Universal Oil Products) Ltd. in the late 1960's and early 1970's. It was constructed as a 105 000 barrels a day (BPSO) grass-roots integrated refinery using mainly UOP technology. It is of a typical physical design for that period and was built at a standard that was relatively good for the standards of the day. It is a single-train integrated facility with only limited intermediate product tankage. The primary operating unit is the Isomax or Hydrocracker Unit. The refinery does not have a catalytic cracking unit. It was designed to process full, sour crude and produce a normal range of fuel products: LPG, gasolines, jet fuel, kerosenes, and fuel oils. The majority of the equipment dates back to the original construction and the refinery units are based upon the technology of Universal Oil Products or UOP as it stood in the late '60's early '70's. However, progressive refurbishing to bring the refinery in line with current industry practice has occurred especially since 1994. The refinery was operated initially by Newfoundland Refining Company Ltd. (NRCL), a subsidiary of Shaheen Natural Resources Company, New York. A fire occurred in the hydrocarbon unit on January 12th, 1976, and in March 1976 the owners were declared bankrupt. The refinery was closed and mothballed before all units could be brought on line. It appears from the evidence presented at the Inquiry that heater 1401 was commissioned and in use in 1975-76; however, little or no information pertaining to it's operations is now available. The mothballed Refinery was idle until 1986 when it was purchased by Newfoundland Processing Limited (NPL), a wholly owned subsidiary of Cumberland Farms Limited - an American company which had no experience in the oil refinery business. NPL renovated and refurbished the equipment and began a progressive start up on the majority of the individual process units. By September 1987 certain of the units were operating and product had been shipped from the refinery. The units became operational as follows:

	Technology	BPSO	In Operation
Crude Distillation		105,000	1987
Vacuum Distillation		50,000	1987
Isomax	UOP	35,000	1988
Platformer	UOP	26,000	1988
Naphtha Hydrobon	UOP	25,000	1988
Distillate Hydrobon	UOP	18,000	1991
LSR Merox	UOP	8,500	1987
Jet Fuel Merox	UOP	20,000	1987
Visbreaker		18,000	1991
Sulphur LTPD		200	1993
Hydrogen (MM.SCFD)		66	1990

Heater 1401 was recommissioned in 1988. Except for the addition in 1989 of a new replacement reformer furnace in the hydrogen unit (and a platformer in 1995), the refinery remained essentially in its original design. (The refinery as to date has maintained and continues to make use of the technical service agreement with UOP the original builder of the refinery.)

In April 1994, a fire occurred on the crude vacuum unit. That event and financial difficulties of NPL caused the refinery to again shut down.

On August 15th, 1994, the refinery was purchased by North Atlantic Refining Ltd. (NARL), a wholly owned subsidiary of Vitol Refining Group of Houston, Texas, USA. Vitol has a long history of business in the petroleum industry. It is a major, privately held, international oil trading company. Vitol Refining group is in turn a wholly owned subsidiary of Vitol Refining B. The Come-by-Chance refinery was the first refinery to be owned by Vitol. NARL operates under a processing agreement with Vitol Refining S. A., a sister company of NARL, which supplies and retains ownership of the Refinery's oil inventory.

The Come-by-Chance Refinery is the 8th largest refinery in Canada which has 17 active oil refineries (as of 2002).

HEATER 1401

A heater is a piece of equipment designed to transmit heat from burner flames to process fluid located within the heater tubes. A heater consists primarily of a structural from, an exterior box, interior tubes, and burners. The burners are devices of steel and refractory which function to release a desired amount of heat with a flame pattern suited to the design of the fire box. The burner moulds the flame shape, maintains a steady flame, maintains the proper quantities of fuel and air, mixes the fuel and air, and thereby minimizes emissions. Burners can produce a round or flat flame and can be positioned at the end or sides of fired heaters. The central part of a burner is the oil gun and this consists of a cast iron manifold, a fuel pipe, a steam pipe, an atomizing chamber and a burner tip. The amount of fuel delivered to the burner is a function of the pressure and viscosity of the fuel oil, and the size of the orifices in the burner tip.

Heater 1401 is a NHT charge heater of the conventional cabin type fired heater with horizontal 5 inch diameter tube coils running through an upper convection section and a lower radiation section. The heater measures about 14 feet wide by 44 feet long and rises about 35 feet overall from the floor. The convection section, which attaches to the top of the transitional hip, is about 4 feet wide and 11 feet high. A self-supporting refractory lined 6 foot diameter steel stack rises about 70 feet from the top of the convection section.

The heater is supported by an exterior steel frame which consists of six contoured columns on each side. Each individual column is fabricated with steel I-beams, and follows the profile of the lower wall, slanted hip, and convection wall, and is commonly called a buckstay. For the purpose of this Inquiry, the buckstays were referring to have been numbered sequentially from the west end.

The sides and ends of the heater are formed by 3/16 inch steel plate surrounded by a perimeter angle iron frame which is bolted to angle iron brackets on the heater. In an effort to reduce air leakage into the fire box some years ago, NARL had employees weld closed the outer seams between the angle iron flanges.

The individual casing panels are backed on the inside with insulation. Originally, the heater panels were lined with a 5 inch layer of monolithic precast Lumnite-Haydite-Vermiculite refractory, which is solid. However, in 1987 this was removed and replaced by 4.5 inches of ceramic fibre blanket. At that time, ceramic fibre blanket was used by many refineries; however, it is not now in general use.

During a planned shutdown in 1996, new panels were installed in the convection section of heater 1401. These new panels had precast refractory lining, and the joint between the existing blanket and the new refractory was packed with fibre at the time.

At material times preceding the event of March 25th, 1998, therefore:

1. The radiation section was fitted with ceramic fibre blanket insulation on the inside of the casing panels; and
2. The convection section was fitted with a 5 inch coating of monolithic refractory.

The heater floor has always been protected with a 5 inch layer of fire brick.

Three natural draught John Zinc DBA-18 oil fired burners are fitted in each end of the heater. Originally, these were on a triangular pitch with two side by side, about 1 to 6 feet about the floor, and the third located centrally about 3 to 7 feet about the floor above the floor. In June 1996, the bottom burners were relocated centrally above the top burner to increase the flame/tube distance. In effect, the triangular pattern was replaced by a vertical pattern of three burners in the vertical alignment The top burner then ended up approximately at the level of tube no. 9.

The burners were designed to operate on fuel gas and liquid refinery fuel oil, but for the past few years they have operated solely on liquid fuel oil (oil fired heaters are not common in the industry). A consideration of the operations using liquid fuel oil will be made later in this report.

Process fluid passes through the heater via four coils in series, with single stream flow from inlet to outlet. The individual tubes are 5 inches in diameter, run horizontally, and are connected by 180 degree return bends at alternate ends. They are about 5 inches apart on the side walls of the radiant section. On March 25th, 1998 the tubes were fabricated from alloyed steel containing, nominally, 5% Chromium, and 0.5% Molybdenum. This tube material was commonly referred to simply as “five chrome” or 5 Cr.

The process fluid, which consists of a mixture of hot naphtha vapour and hydrogen, along with such impurities as hydrogen sulphide (H_2S), enters the heater at the top and passes down through four coils in the convection section at the top of the heater, where heat is transferred from the rising combustion gases.

The heater was designed to raise the temperature of the naphtha from 535°F at the inlet to 695°F at the outlet.

The radiant section is at the bottom of the furnace and is the area where the tubes gain heat primarily from burner flame radiation, and partly from convection currents at the firebox walls.

From a flow point of view:

1. Outlets on the north and south circuits of the convection section enter the top of the upper radiant coils on the north and south wall respectively; and

2. The outlets from the two inner coils of the convection section connect to two pipes which run down the outside fo the east wall to the bottom of the lower radiant coils on the north and south wall.

The last tube in each of the four radiant coils, being tubes no. 9 and no. 10 up from the floor, continue out through the west wall and connect with flanges to a common outlet manifold from where the process fluid flows to the NHT reactor.

By convection, the passes within the radiant section of heater 1401, are number as follows:

1. Pass #1: North wall, top coil,
2. Pass #2: North wall, bottom coil,
3. Pass #3: South wall, bottom coil,
4. Pass #4: South wall, top coil.

The UOP specifications for heater 1401, designate the following process requirements:

Throughput, 1bs/hour	221,150
Molecular Weight at inlet	72.8
Mol percent H2	28.6
Inlet deg F	535
Outlet deg F	95
Design Pressure psig	560
Weight percent, Vapour at inlet	100
Weight percent, Vapour at outlet	100

Molecular weight at outlet	72.8
Heat absorption (normal, radiant), 10 to the power of 6 BTU/hr	24,260
Heat absorption (normal, conv), 10 to the power of 6 BTU/hr	6,940

The Procon (Great Briton) Limited in July 1970, adopted UOP specifications and added the following specifications concerning heater 1401:

Liquid flow - inlet and outlet - 1b/hr	0
Maximum flux density, radiant tubes (Btu/hr/ft squared)	18,000
Design pressure, psig	560
Hydrostatic test pressure, psig	1,100
Maximum tube wall temperature deg. F (radiant)	771
Tube material	5% Chrome, 0.5 Moly

HISTORY OF HEATER 1401

I believe a detailed review of the operations history of heater 1401 is in order so as to understand the circumstance surrounding the March 25, 1998 incident. The evidence presented at the Inquiry shows that heater 1401 operated for approximately two years, from 1974-76. The Refinery was then shut down for 11 years. The heater was placed back in operation in 1987 after Newfoundland Processing (NPL) purchased the Refinery in 1986. When they purchased the Refinery, NPL began to refurbish the moth balled refinery with the help of UOP. By September 1987, the Refinery was producing some product.

In 1987 non-destructive testing was conducted by ultrasonic thickness measurements on the tubes of heater 1401. The measurements at the "approximate" location of the 1998 rupture was 0.290 w.t. (two other measurements were taken - .290 at the centre and .275 at the east end of the tube). Heater 1401 was inspected in 1988, including the tubes and ceramic blanket insulation that had been installed as a replacement for the original castable insulation, and was found to be in good condition.

On March 29th, 1988 two explosions occurred simultaneously in heaters 1401 and 1501 during NHT and platformer startup. The fuel pressure of the RFO supplied to the heater burner dropped and the burner fires were extinguished. The burner pilots were malfunctioning and fuel entering the heater was not burned off. Vapours accumulated and ignited, probably from hot surfaces inside the heater. The resulting internal explosion pushed the steel panel of the heater box from 1401 outwards, deforming it and blowing off the side of the heater. Many of the tubes were bent. There was no fire. It is not clear how many of the original tubes were replaced at that time; however, tube no. 9 was not replaced and the same original tube was in use on March 25th, 1998. Neither the condition of the tubes, the heater casing, or insulation, nor the manner of operation of the heater contributed to the 1988 incident.

In 1989-93 structural testing was conducted on the tubes of 1401. The following results were obtained from a location (not necessarily the same location each year). Near to the location of the rupture in March 1998, the original thickness of the tubes were .258.

DATE	Type of NDE	NDE Performed by	Result of NDE			
			W. U. Bend	W. End	E. End	E. U. Bend
Sept. 14, 1989	UT	NPL	.258 w.t.	.278 w.t	.277 w.t.	.295 w.t.
Oct. 26, 1991	UT	NPL	.253 w.t.	.252 .237	.287 .299	.398
Aug 27, 1992	UT	NPL	.241 w.t.	.254?		.374
1993	UT & BHN	NPL	0.257 w.t. 198 BHN (7 feet from E. End)			

w.t. Wall thickness in inches
UT Thickness testing to check for thinning of tubes
BHN Brinnell Hardness Number used to check the integrity of the metal tubing

The Department of Labour inspected heater 1401 and certified it for operation in 1989. In 1990 the Department of Labour carried out an inspection of the heater and nothing other than routine repairs was required. The ceramic blanket was found to be in good condition at that time.

The Department of Labour's inspection in 1991 noted that there had been deterioration in the ceramic blanket and a recommendation was made for repair on the next shutdown. There is no evidence that this was actually done.

In August, 1992, the Department of Labour inspection noted a build up of contaminate behind the ceramic insulation. The pins and anchor washers that held the blanket in place were corroding. In October, 1992, 90% of the hot faced blanket was replaced, the tubes were cleaned and inspected, and the heater was re-certified by the Department of Labour.

In July, 1993, NPL inspectors observed flames impinging on the tubes on the north side of the heater. Inspection reports were prepared on July 8th and July 13th, describing these observations. On July 27th, 1993, tube 3 on the North wall ruptured. The rupture created a 30 inch fish mouth fracture with thick lips with a maximum width of 13 inches located about 5 feet from the east end of the heater. The rupture caused release of processed fluid and a fire occurred that was contained in the heater box. ERA Technology Ltd., a metallurgical consulting company concluded, after an investigation and on the basis of photomicrographs provided to ERA, that the failure of the tube was probably the result of creep due to long-term over heating. Repairs were carried out and two lower tubes were replaced on the north and south walls. The ceramic fibre insulation blanket was largely replaced. Nondestructive UT and BHN hardness tests and caliber testing of the outside diameters of the tube damages were carried out. The tube repair and pressure testing of the new tubes was carried out with the Department of Labour present and the heater was re-certified.

On August 25, 1993, a suspect flame pattern was observed in heater 1401 and a crack in the tube was suspected. The heater was immediately shut down. It was discovered that there was a crack in the weld that connected the newly installed tube to the old one. There was a 6 inch bulge in the old unreplaced tube adjacent to the weld crack (tube no. 2 northwest wall). Another bulge with a hairline crack (tight crack) was discovered in the second tube from the bottom of the southern corner (tube no 2). The failures were investigated by NPL personnel, Department of Labour, and by consultants from Marenco Engineering and Born Heaters (retained by NPL and the original designer of the heater). It was determined that the failures were due to localized overheating of the bottom tubes. These were the tubes nearest the two lower burners in the triangular burner pattern installed in 1401. It was also determined that the insulation blanket was installed too close to the backside of the tubes, leading to increased heat demand on the hot or fireside of the tubes. Further, it was determined that the burners in use in 1401 were designed for use in black oil heaters and emitted more heat than those specifically designed for 1401. As a result, NPL replaced all six bottom tubes (tubes 1-6 inclusive) on each wall of the radiant section of the heater with new tubes. The burners were replaced with appropriate units. When 1401 was designed, thermocouples were not used on heaters in the refinery business. Although they were not in general use in refineries in 1993, NPL install two knife-edge type 410 tube skin thermocouples on tube no. 2, 5 feet from the west bend and east bend which were the tubes nearest the burners. These are the tubes that had previously failed. Thermocouples are intended to measure the temperature on the outside of the tubes. Their purpose is to measure the skin temperature to monitor whether overheating is occurring (UOP considered skin thermocouples to be only reliable as trend indicators and not for absolute measure of temperature and it has been noted that they usually read 30-60°C higher than the actual temperature).

In December 1993, a shutdown occurred at the Refinery. Marenco Engineering carried out an insitu metallography on tube no. 3 in the four corners of the heater, the areas most likely to be affected by flame impingement. No problems were discovered. The ceramic blanket was noted to be in serviceable condition at that time.

In March 1994, Atlas Testing Lab and Services Ltd. carried out radiography, or x-ray imaging on tubes no. 1 northwest and no. 3 northwest on the north side, and no. 2 southwest and no. 4 southwest on the south side of the heater. No noticeable coke buildup was reported.

The Refinery was shut down after an unrelated fire in 1994. On August 15, 1994, the Refinery was purchased by Vitol Holdings PV whose operating company was North Atlantic Refining Ltd. (NARL). NARL immediately commenced inspection and a refurbishment of the Refinery, including heater 1401. An initial inspection was carried out on heater 1401 on September 12, 1994, by Bob Stacey of NARL's Inspection Department. That inspection disclosed that the tubes in the radiant and hip convection sections were coated with combustion product. The tube hangers were serviceable. The blanket insulation was generally intact; however some was oil saturated and some had fallen onto the tubes in the convection section. Burner surrounding refractory showed slight cracking and the burner muffle boxes and refractory were failing. It was recommended that all burners be overhauled and rebuilt and that the floor fire brick be lifted and relaid. The casing, roof, hip roof, and side walls all showed evidence of bulging due to the internal explosion in 1988 and all had visible corrosion attacks (north and south walls). It was recommended that the heater be scaffolded up to the convection level and all accessible tubes be cleaned throughout the heater so as to allow further inspection.

On September 14, 1994, a hydrostatic test of the tubes was carried out at 1300 p.s.i for 30 minutes. Some dispute arose at the Inquiry as to the correct pressure to be use for hydrostatic testing. The design conditions for heater 1401 states that hydrostatic pressure is 1100 1b psig(Procon G.B. Ltd., July 15th, 1970). The UOP Engineering Standard 8-1001-1, Field Pressure Testing of Piping systems sets out a formula to determine hydrostatic test pressure (Inquiry Book IV A). Curtis Williams, P. Eng. (one engineer who prepared a detailed report on the March 25, 1998 incident), testified that he used this formula to calculate the correct hydrostatic pressure for testing purposes and calculated 1312.5 psig and 560 psig at 800°F. In his notes showing the calculation, he noted that the manufacturers test pressure was 1100 psig at 100°F. Allison Tupper, P. Eng., testified that the increased test pressure used on September 14, 1994 could have caused an aggravated stress accumulation, promoted stress related corrosion and had other deleterious effects on the subject tube. He opined that this could have well caused a shortening of the useful life of the tube. The calculations done by Curtis Williams were at 800°F, whereas the manufacturer's temperature for testing was 100°F. I have no evidence to say that a different temperature would increase the recommended hydrostatic testing pressure. I am, therefore, unable to determine with any certainty that the 1994 hydrostatic tests contributed to the 1998 failure. Being that A. Tupper and C. Williams are highly qualified engineers, I can only conclude that the 1300 psig hydrostatic test 'may' have had an effect on the tube in 1994. I note that A. Tupper opined that it 'could' have caused a problem; however, he too appears to be uncertain. Unlike other area of A. Tupper's report, he does not make his opinion on this topic to any degree of probability.

No leaks, weeps or distortions occurred as a result of the hydrostatic test performed on September 14th, 1994, and it was deemed to be satisfactory.

On September 30th, 1994, Atlas Testing Labs and Services (Nfld.) Ltd. conducted UT testing of the tubes at heater 1401. It noted the original tube thickness as being .258 (mw) and a retirement thickness of 0.133 (mw). In the radiant section of heater 1401, only tubes 1-6 inclusive were tested; however, all the tubes in the convection section were tested. Tubes 7-9 inclusive in the radiant section were not tested.

On October 5th, 1994, another internal inspection was carried out on the heater. The radiant section tubes were observed to be coated with medium to heavy deposits, dry on the upper surface and wet on the bottom and sides. The tube supports and hangers were in place and visually secure. The blanket insulation throughout the visible areas of the fire box was generally intact. The center area of the radiant section area blanket (north and south side) showed some oil/deposit, saturation for the first 1 inch of the blanket. The burner surround refractory showed some cracking but was serviceable for another run. However, the baffle muffle block boxes were burned out and the refractory had failed. It was recommended that all burners be pulled and serviced/repaired and this was, in fact, carried out at the next shutdown. The floor fire brick required lifting and relaying at the same time. It was noted that there were a number of holes in the roof and casing due to blanket failure and corrosion of the steel plate. The casing, roof and hip section steel panels were in poor condition and showed bulging and distortion due to the previous internal fire box explosion in 1988. Replacement of the panel section and repair was conducted where feasible prior to installing the new blanket. It was recommended that:

1. Ceramic blanket be replaced at the next shutdown with a suitable cast or gunned refractory
2. A substantial rebuild and new stack section be carried out at the next turnaround.

The inspection report noted that UT testing had been carried out by Atlas on the "accessible" tubes of the heater and the results had been reviewed by Refinery staff. No "serious" bulging or bowing of the tubes was visually observed at this time.

Further inspections were carried out on October 7th and October 15th, 1994. They related to the hip and convection sections and it was noted that repairs should be made to the convection section wall panels and the convection tubes needed to be cleaned.

The inspection process between August-October 1994, was part of the general inspection of all equipment at the Refinery by NARL. One of the purposes was to identify work that needed to be done immediately so as to enable the Refinery to be reactivated. Further, the inspection results were to be made part of a long-term planning program for major capital investment by NARL.

The evidence indicates that the tubes were cleaned, some ceramic blanket was replaced and the burner and surrounding refractory were repaired and serviced. Some steel panels were replaced in the roof area and in the ducting leading to the stack.

At the Inquiry NARL submitted that by early 1995 it had developed a list of priorities for the Refinery refurbishment and improvement, including a heater improvement program, safety program, and modernizing process control instrumentation. No written evidence of any 1995 plan of a phased in heater improvement program was presented to the Inquiry. Not until 1996 did NARL set up a heater improvement group. Part of the mandate of that group was to complete a review and make recommendations on future work as well as to implement heater operating improvements. A review of the documentation concerning this group indicates that it concentrated its efforts on heater operation efficiency and cost savings, more than physical improvements to the heater and the safety of it's operations. However, work was carried out on heater 1401 after the initial refurbishment. That work appears to have been carried out on a need-to-be-done basis, rather than any long-term plan.

Heater 1401 was inspected on February 15th, 1995. At that time, perforations at and around the stack damper were noted and a buckled area in the same local was observed. The engineer who carried out the inspection stated, “I don’t believe this is serious, it should be inspected closely at the first down time.”

On the 17th of February, 1995, a detailed inspection was carried out of the stack area of heater 1401. UT readings were taken on the stack. Holes and deformities were apparent and a recommendation was made that the stack should be replaced to include castable refractory (Hi-Alumina) on the next shut down. A design of the stack area noted the location of the perforation and buckling. A series of 8-10 small holes are shown just below the damper (buckled in about 3/4" on the north side) and above the hip section.

On the 19th of May, 1995, J. Trahey wrote to D. Huckeby (c.c. to other department heads) recommending replacement of the stack. The recommendation was based on the “severely deteriorating condition, reduced structural integrity of the existing stack”. The cost of the replacement was estimated at $64,325.00 (including castable) refractory and the anchors. On the same day, Quality Control Inspection Engineer, Curtis Williams, conducted a detailed inspection of the top half of the stack of 1401. It included UT and visual inspection. He found:

1. Of ninety-three thickness readings taken, seven were below retiring and forty readings were found to be approaching retiring.
2. There is heavy corrosion inside the stack.
3. There were 16 holes as a result of corrosion through the metal.

4. Patches have been installed on this stack in the past.

He commented, "50% of the stack material has past or is approaching retirement thickness, combined with the number of holes through this stack, renewal of the stack is recommended." The refinery was shutdown for 63 days between April 16 and June 16, 1995, for a planned turnaround. A new stack lined with refractory insulation was installed at that time on heater 1401.

Early in November 1995, prior to the November 14-20 shutdown, an inspection of 1401 noted that some of the ceramic blanket had separated and one piece had fallen just above the peep hole in the west end of the heater. It was difficult to determine exactly how much insulation had fallen; however, Randy Spurrell of the Inspection Department of NARL noted that, "precautions should be taken to install insulated panels on the west end in case the blanket does fall off. Also, operations should check the heater more often as well as Q.C. because if such insulation falls of, it may knock out the fires in this area." He recommended that insulation paneling be installed to the tip of the roof. A note on the report states that repairs to this situation were made in January 1996 (an unscheduled shutdown after a tube rupture in 1401).

On November 16th, 1995, U.T. testing was carried out on the west end of tube nine. It showed a reading of 0.243 wt. The UT testing done gave five readings on each tube of 1-6, but only one reading for tubes 7-9 inclusive, taken at the west u-bend for tubes 7-9 inclusive. On the same day, an insitu metallography evaluation of 1401 was conducted by Drewan Engineering Ltd. NARL instructed

Drewan to conduct this examination of the tubes in 1401. The reason given for the examination was concern that there might be over firing in the heater. The examination was "part of an investigation carried out during a scheduled shutdown to determine the condition of the heater tubes."

Drewan took six replicas of tube 4, 10 feet from the east wall of the east corner, and from the center of the north and south walls. These areas were chosen as from past experience with this type of heater, these locations were more vulnerable to flame impingement. The location was also chosen based on visual evidence of possible over firing during operation. Tube 4 was one of the newer tubes installed in September 1993. The Drewan report explained that the original micro structure of the material from which the tubes were manufactured was a spherical carbide particle in a ferrite mix. As the tubes were exposed to elevated temperatures, the micro structure will change. These changes can be determined by analysis of the tubes. The higher the temperature, the faster the changes occur. By examining the tube micro structure on a regular basis, these changes can be monitored to determine the estimated remaining life expectancy of the tubes. Any tubes which are exhibiting signs of significant creep can be removed and replaced.

Drewan found no evidence of carbide granules in the samples examined and there was no indication of overheating on the examined tubes. They did note, however, a difference in carbide distribution between the tubes replicas taken from the north and the replicas taken from the south walls. Drewan opined that the difference could be attributable to the south wall being consistently exposed to higher temperatures than the north wall. It noted that tubes on the south side wall were manufactured by a different manufacturer than those installed on the north wall, and the different chemical content may have occurred during the milling of the tubes. It appears that Drewan believed the later explanation was more probable.

As a result of this inconsistency that may arise due to the manufacturing process of tubes, Drewan recommended that if a sample of each new tube (½ " ring) was taken from each new tube, it would allow the exact micro structure of the new tube to be determined before its use. A future sample taken from the tube during its operational life would permit an exact determination of any changes in the micro structure to be determined which would enable a more reliable estimate of the remaining life of the tubes to be made. No evidence was tendered to the Inquiry that NARL adopted this recommendation before March 1998.

In an inspection reported dated 16 November, 1995, (signed on December 15, 1995) prepared by Curtis Williams, P. Eng. for Bob Stacey, it was noted that the heater was opened up for inspection primarily to perform repair to the ceramic blanket and investigate any possible metallurgical damage to the radiant wall heater tubes as a result of observed flame impingement during the last run.

Relevant sections of the report stated:

Refractory & Casing:

i. Blanketing was completely replaced on west wall due to deteriorations.

The heater skin casing exposed upon removal of the old blanket is intact, however, visual inspection shows corrosion to be very active. Products of fuel oil combustion have penetrated the blanketing and condensed on the steel casing. A layer of wet paste-like material is present on all areas. Skin casing seams are spreading apart inside. The result is active corrosion in the panel seams which will soon work its way through to the exterior. Approximately fifty percent of the blanket pins fell off or had to be replaced, (as a result of corrosion).

ii. One area of blanketing was replaced on the north wall due to deterioration, (approximately 12 feet x 5 feet in size located six to seven feet from the floor, centered on the radiant wall). Visual inspection of the exposed casing underneath matches conditions identified on the west wall skin casing in (i) above. A check of the existing blanket where the patch has been removed revealed a build up of deposit between the blanket and skin casing. The deposit is sulphurous in nature and up to an inch in depth. This deposit is pushing the blanketing away from the skin casing, accelerating the deterioration of the skin casing, blanket pins, and subsequently the blanket itself. The entire heater box area is ceramic fibre blanket lined and as such subject to this problem

iii. The remainder of the ceramic fibre blanket inspected was found to be intact, however, considering the corrosion activity noted between the blanket and skin casing, extensive ceramic fibre blanket repairs along with some skin casing repairs can be anticipated for the next turn around.

iv. The burner refractory on the east side is showing signed of deterioration. The refractory crumbles under the application of only a light force. It has cracked open in several placed. Repairs can be anticipated for next shutdown.

Tubes:

i. A heavy thick layer of fuel ash is resting on the top of all the tubes. Beneath this there is a thinner layer of deposit which completely covers the circumference of the tube. This second layer can easily be removed by hand scraping. At the tube surface there is a very hard chromium oxide scale, (this layer is extremely thin). A visual inspection of the tubes shows no appreciable signs of external corrosion. On the older tubes, (no. 7 and up on north radiant wall and no. 6 and up on the south radiant wall) there is extremely small, tight pitting present throughout the surface approximately 0.005 inches deep. Those tubes installed in 1993 show no signs of corrosion. A total of six new thermocouples were installed in this heater by M & M Engineering Limited. These thermocouples are Gayesco Type 310SS Shielded Design installed as follows: (1) south wall - one on tube number two, east end, five feet from return bend and two on tube number five, twelve feet from the return bends; (2) north wall - one on tube number two, west end, five feet from return bend and two on tube number five, twelve feet from the return bends. These thermocouples are in addition to the two Knife Edge Type 410SS Thermocouples already operational on this heater. These couples were installed in September of 1993 as follows: (1) south wall - one on tube number two, west end, five feet from return bend; (2) north wall - one on tube number two, east end, five feet from the return bend.

Burners:

i All pilot gas tips required replacement. All fuel oil guns need to be cleaned. Fuel gas supply is isolated and blinded. All fuel gas burners will require replacement before being used again.

Tube Hangers:

i All accessible tube hangers are sound. Shock tube hangers on the west end were inspected and found to be suitable for continued service.

Floor:

i Floor condition acceptable, (no bricks missing). To be swept clean before closure.

Foundation & Supports:

i The second support column from the east, (on the exterior of the heater), where the column runs from the inclined hip section to the vertical convection section is slightly distorted, (approximately 2 inches). The cause and the duration in existence is presently unknown. The structure does appear to be sound and as such no repairs are recommended. Inspection will continue to monitor the structural for any changes in condition.

ii The inlet piping supports, (spring hanger support and associated structural steel on the west end), are warped. Visual inspection of welds and steel work did not reveal any signs of cracking of serious corrosion. The present state of this steal work is attributed to past failures experienced on this heater from which no repairs were initiated. Although the warpage is not serious enough to impact on the current operability of the unit, the overall structure requires replacement. Replacement in-kind is not recommended; however, as the current design can be greatly improved upon. The plant engineering department to be consulted in this matter.

iv. The concrete support at the south west corner of the heater is badly damaged and requires replacement.

v. All ladders, platforms and other attachments to the heater show signs of light atmospheric corrosion but remain structurally sound.

vi. This heater requires sandblasting, priming, and a coat of paint.

NDT (Ultrasonic, Hardness, Radiographic, etc...):

i. Ultrasonic thickness measurements were taken on all accessible tubes. No tube wall thickness measurements taken were found to be below the retiring thickness. Ultrasonic thickness measurements taken on this heater over the past six years are being compiled so as to establish a corrosion rate for the tubes which can then be used to calculate the remaining life of the heater tubes. (Report to follow)

ii. Metallographic examination was conducted on the heater tubes at six locations. Refer to the attached report by Drewan Engineering Limited.

Repairs:

i. Ceramic fibre blanket completely replaced on west wall.

ii. Ceramic fibre blanket repaired on north wall. Area of approximately 12 feet x 5 feet in size located six to seven feet from the floor, centered on the radiant wall.

Recommendations:

95-11-27

i. Replace ceramic fibre blanket in fire box of heater. Recommend use a castable type refractory suitable for the type of refinery fuel oil fired in our heaters.

ii. Repair the burner refractory on the east end of the heater.

iii. In addition to inspection of the fire box, open the convection section for inspection of the convection coil, breeching stack and damper next turn around.

iv. Repair the inlet piping supports as identified by item ii under the section "Foundation and Supports" in this report. Engineering design will be required.

v. Replace all pilot gas burner tips. Clean all fuel oil burners.

vi. Repair the concrete support at the south west corner of the heater.

Copies of the report were sent to senior refinery management and department heads and a UOP representative.

It should be noted that new thermocouples were placed on tube 2, one of the new tubes installed in 1993. Even though evidence of pitting was found on tube 7 and up north radiant wall and 6 and up on the south radiant wall., no additional ultrasonic testing was conducted on these older tubes at the time. However, one UT reading was taken at the west end of the 9 north and one reading at the u-bend of tubes 7 and 8. The only repairs carried out on heater 1401 between November 16-20, 1995, were complete replacement of the ceramic blanket on the west end and repairs to the blanket on the north radiant wall.

Heater 1401 was designed for an absorbed heat (mm BTU'hours) of 24.46 in the radiant section and 6.94 in the convection section, for a total of 31.40. Between January 11, 1995, and January 26, 1996, heater 1401 was run between 33.4 to 38.95 mm BTU's. At the same time the design duty of the furnace exceeded the maximum recommended design duty between 106.5% and 124%. The maximum absorbed heat reached was 38.95 on January 26 at which date the furnace design duty reached 124%. This is called a hard firing and is operating the furnace under high firing conditions (above design). At the same time fuel oil pressure (95.96 Psig) and viscosity was high (20,250 Cst and 9,000 Cst 210°F Average) and the preheat temperature was only between 470-475°F, rather than the optimum temperature of over 500°F. The optimum temperature according to the design of the heater is 535°F at the inlet.

On Saturday, January 27, 1995, at approximately 10:00 a.m., flame was observed coming from tube 3, south wall, approximately 14 inches from the return bend. The heater was shutdown without incident and opened for inspection. A visual inspection on the tube discovered three failed locations along the hot face side of the tube centered within two bulges. The report of the incident filed by Bob Stacey dated 27 of January, 1995, indicates that "all tubes were inspected visually, and checked for hardness, wall thickness, and gauged for possible creep damage". The gauging revealed bulging on the third tube up on the north wall approximately 14 inches from the bend weld, opposite the failed location on the south wall. The alleged hardness UT checks on all tubes is not supported by the NDT test results tendered at the Inquiry and the evidence indicates that hardness readings were only checked at eight locations only along tubes 2 and 4 with values ranging from 155 to180 BHN (acceptable ranged for 5 CR - ½ MO is 131-231BHb). Ultrasonic thickness measurements were only taken at the same locations as the hardness readings. No ultrasonic report was attached to this report and none was introduced into evidence at the Inquiry. It appears that no ultrasonic or hardness testing was conducted on tubes 5 to 9 inclusive at that time. The January 27, 1995 failures in the tubes occurred in an area that was in close proximity to the bottom two burners of the triangular burner pattern in 1401. An investigation concluded that the probable cause of the tube failures was hard firing of the heaters at 15-20% more than the designed absorbed heat duty and flame impingement on the heater tubes causing localized overheating of the tubes closest to the bottom burners. A failure analysis conducted by Drewan Engineering indicated a creep failure due to high temperature after less than three years of operational use of this tube. As a result, tubes 2 and 3 south wall from the center of the heater to the east end were replaced. to the return bend. Tube 3, north wall, from the return bend to the center of the heater was also replaced. Three skin thermocouples were installed on tube 2, from the bottom, north east, south east and south west corners. The old tubes removed from the heater (as a result of the new tubes being installed) showed coke deposits on the inside diameter (ID) of the tube up to a maximum thickness of 1/8". Unburned hydrocarbon scale was removed from tubes 1 to 7, inclusive, either by hand or by chipping at the same time as the new tubes was installed. It was also noted that evidence of tube hanger overheating was apparent. Tube hangers on tubes 4, 5 and 6 of the south wall sagged visibly and the second column of hooks from the east and the bottom five tube hangers visibly sagged. It was recommended that 12 new tube hangers be purchased for installation during the next turnaround.

A review of the operational data from 1996 to March 1998, showed that neither the absorbed heat nor the design duty of the furnace were exceeded after January 1996 to March 1998. In 1996 NARL restricted the fuel oil pressure to the heater (80 Psig) and adjusted the rate of the naphtha feed to keep the heater within its design firing duty.

The heater group came in to existence in 1996. The evidence indicates that it considered improving burner performance so as to increase its efficiency.

Contact was made by that group with John Zinc Co., the manufacturer of the heater, for assistance and advice. Heater operation manuals were developed and training was carried out internally and by attendance by some staff at a Fired Heater Design course, sponsored by UPO in March 1996. The heater group continued to monitor overall heater performance and efficiency.

Between January 1996 and the July 2, 1996 turnaround heater 1401 operated at 85-93% of its design absorbed process heat duty. The heater output temperature was lowered as was the feed rate from 22,400 barrels per day (Bpd) in March 1996 to around 20,000 Bpd in May/June 1996. This was necessitated in order to limit heater duty due to fouling of the preheat exchangers. RFO was between 80 to 85 Psig. However, viscosity remained high and by June 1996, had escalated to between 23-30,000 Cst at 210°F.

During the July 2-19 shutdown in 1996, an inspection was carried out on heater 1401 by NARL quality control inspectors. A memo dated 9/6/94 from Curtis Williams to R. Spurrell states:

1. Repair damaged blanket mid/center north radiant wall, approximately 6 x 6 scaffolding required.
2. Wire brush - hand clean accessible tubes to remove loose deposits.
3. Replace damaged skill T/W's. Procedure being prepared to modify existing T/W's installed.
4. Sweep up floor prior to closure. Ensure expansion joints are cleaned out.

The inspection report dated 7/11/1996 confirms that four new thermocouples were installed, however, it does not indicate where they were located. New burner cans were installed. A 6 x 6 section of ceramic blanket was installed on the mid center of the north wall, the tubes were cleaned and the floor area expansion joints swept clean. The tubes were inspected visually and found to be in good condition. There was no indication of bulging or other distortions indicating potential creep damage. A light deposit was observed on the surfaces with only minor scaling noted. The accessible tubes were checked using o.d. calipers for possible creep damage with no discrepancies reported. B. Stacey, who prepared the inspection report, recommended the purchase of 40 new wall hangers for the next turn around. He recommended that these new hangers be upgraded metallurgically to comply with ASTM A560 (50Cr/50 Ni with Cb Stabililizer). At the time of the shutdown, the Department of Government Services and Lands inspected and recertified heater 1401 for another two years of operation. Although not noted in the inspection report for heater 1401, the heat exchangers that pre-heated the fuel feed to 1401 were cleaned in the summer of 1996. This improved the operating performance of the exchangers and thus reduced the load of heater 1401. The inlet temperatures for May 1996 to June 27, 1996 varied from 470-480°F. From August 13-Nov 11, 1995 it varied from 499-516°F. The convection section was also cleaned in the July shut down.

The NHT was upset twice during August 1996 and the heater was subjected to thermal shocks - once by a charged pump failure and once by a power failure. The heater was brought up to operation after both instances with no apparent problems. RFO pressure varied from 70-83 Psig during this time period. Viscosity varied from 4,000 - 6,000 Cst with a jump to 10,000 - 15,000 Cst in late August and early September. From October to November 11, the feed rate was around 22,000 Bpd at 75-80% design heat load, 80-83 Psig RFU pressure at 6,000 - 7,000 Cst.

On November 12, 1996 a crack was identified in a bulge on tube 5 on the south wall of the heater. The heater was shut down without incident. The tube was replaced. This failure was attributed to creep failure due to overheating (B. Walsh, November 25, 1996). One UT measurement was carried out on each tube at that time. Tube 9 was tested at the second column from the west and showed .252 w.t. This is greater than the 1995 measurement of .243 (at a different location). The variation in UT results on tube 9 for 1989 to 1996 (as with other tubes in the 7-9 range) indicates little or no thinning of the tubes even after nine years of use.

After the second tube failure in 1996, refinery staff became concerned. Evidence presented at the Inquiry shows a flurry of activity after the failure. Data was requested from operations and quality control amongst other matters as to the rate of feed, fuel oil pressure, firing duty, skin temperature, and viscosity.

At a morning planning meeting held November 25, 1996, the condition of Heater 1401 was discussed in some detail. It was noted that RFO pressure had increased and the firing conditions inside the heater had deteriorated somewhat.

Hot combustion gases regularly and randomly were disturbing the burner flames. It was believed that the November 12th tube failure appeared to have resulted from creep failure due to overheating 'and was apparently a difficult situation to predict'.

The RFO pressure increased from 80 - 84 psg to 90 in one week. Reasons for that increase were discussed; ambient air temperatures, inlet temperatures, wind conditions, RFO viscosity and the recycled gas rate were all discussed. Action steps were discussed. It was decided, amongst other things, that:

1. Wind breaks would be installed to reduced wind affect on the flame pattern.
2. The conditions of the regenerative tile is such that control of combustion air is difficult. Repairs necessary.
3. Discontinue sweet Naphtha feed production. The effect of this decision was to increase the sulphur content in the naphtha feed from 0.30 ppmw to 0.90 ppmw.

The decision to discontinue the sweet naphtha feed was made by productions planning.

A copy of the notes of the meeting was sent to all senior management, including M. Serinivasa in operations who in a letter to the refinery management dated November 14, 1996, (indicating operational data for Heater 1401) said at the very end of the letter, "The effect of type of crude processed on possible corrosion of the tubes will be looked into separately. I note that Curtis Williams received neither a copy of the November 14 letter nor the November 25 memorandum, yet at this time he was preparing a tube life fracture analysis for 1401, which included a corrosion of H-1401."

On November 25, 1996, Curtis Williams, P. Eng., presented a tube life fracture analysis for H 1401. Many senior operations and maintenance personal attended this meeting. The tube life fracture analysis compared 5 Cr-1/ 2 Mo tubes with 9 Cr - 1 Mo tubes. The model he used was based on Rupture Design (Higher Temperatures) from American Petroleum Institute (API) 530 recommended practice for the calculation of heater tube thickness for petroleum refineries. His calculations were premised on the following assumption:

1. Tube life of six years.
2. At a constant operating pressure of 560 Psig.
3. Corrosion rate of 4 MPY.

Mr. Williams carefully noted that this operating pressure and corrosion rate were selected for comparative purposes only and did not necessarily reflect the true corrosion rates for 1401. He noted that even small temperatures excursions from the norm should be avoided and the effect of an increase in temperature on the remaining tube life is cumulative in nature. He noted that the API analysis is purely mechanical and does not consider the benefits of metallurgical upgrades with respect to corrosion. The final report of Curtis Williams, P. Eng., considered at the later December 3 meeting by senior management stated in black bold letters "The mechanisms of corrosion to the tubes in this heater is considered to be sulfide corrosion to the tubes i.d.'s"

Mr. Williams established that the H_2S composition established by the processing department is 0.35 Mol. Using that rate, he opined that using 595°F the corrosion rate would be 10 to 15 MPY for 5-Cr steel, but at 675°F the corrosion rate would be 20-30 MPY. Theoretically using some process conditions would reduce the corrosion rate in 9-Cr steel to less than 5 MPY in the upper pass and 10 MPY in the lower passes. Initially, he calculated a corrosion rate approaching 30 MPY for the lower radiant wall tubes, however using process data for the period from September 30, 1994 to November 14, 1996, much of which occurred between September 1994 and November 1995, he opined that the rate was 13.5 MPY. He was careful to emphasize that short term corrosion rates since November 1996 showed negligible corrosion.

He used the time frame June 1987 to August 1992 (not including the new tubes installed in 1993, but including tubes 7 - 9) to calculate the long term corrosion in both the lower and upper radiant sections to an average of less than 10 MPY. He noted that there appears to have been a period of accelerated corrosion in the upper heater passes (as determined for analysis of the tubes removed in 1993). However, he carefully notes that the data is somewhat limited and can only narrow down the accelerated rate between August 1992 and November 1995.

Mr. Williams, in his report, recommended 9 - Cr - 1 Mo tube be installed to improve the situation as it was two to three times more corrosion resistant than 5-Cr - ½ Mo material.

After this review of corrosion rates, Mr. Williams concluded that, "I think the need to resist sulphide corrosion is secondary to the need to resist creep rupture". He again emphasized that regardless of whether 5 or 9-Cr steel was used, minor temperature excursions can have a tremendous impact on the remaining life of the tubes. The last two paragraphs of the report state:

> It is possible to draw a correlation between corrosion rate and the recent failures in this heaters. The recent failures are the likely result of tube damage caused by prolonged over firing of the heater during a period of time between the end of 1993 and 1995, when corrosion rates in this heater accelerated. These types of failure are possible due to the cumulative nature of creep damage.
> It has been recommended that the heater metallurgy of the bottom passes be upgraded 9 Cr - 1Mo. To properly design for a new heater coil a decision on maximum operating temperatures and pressure is required so that operation within the creep rupture boundary can be avoided. Furthermore, correlation of accelerated corrosion rates in the top and bottom passes of the heater suggest possible creep damage to the tubes in the top pass as well, (due to possible over firing). <u>I would suggest at a minimum that samples be removed from the top pass radiant tubes for remaining tube life evaluation.</u> (underlining added)

This report clearly point to sulphide corrosion as an important factor in calculating tube loss in 1401. It pointed out that to date the ruptures were caused by prolonged firing and hence the need to resist sulphide corrosion should be secondary to the need to resist creep. However, it is clear that by December 1996 refinery managers were clearly aware of corrosion in heater 1401 and its potential consequences.

At a December 3, 1996, meeting attended by management, process, operations, heater group, quality control and a member of the SHE committee, the contents of C. Williams' November 25 report were considered, and in fact, important aspects of the report were hi-lighted in black bold lettering. In the introduction to the minutes of the meeting provided to the inquiry it says, "The recent tube leak in H 1401 is unto itself would dictate an investigation. However, there have been several failures in this particular heater. A relationship between these may exist and, if so, may indicate a factor which is systematic".

The meeting reviewed past failures, operating and firing conditions, design practices, and corrosion effects. Expertise resources were considered and all known data and information were surveyed. The purpose of the meeting was to initiate the process of identifying the root cause of the recent tube leak in 1401.

The meeting considered corrosion in some detail. The minutes state:

> 2.3.1 It is evident that a layer of iron sulphides has been created on the inner diameter. The source of the scale may be either from corrosion products out of upstream units or to direct attack on the tube. The scale forms an insulating layer, impeding heat transfer. Therefore, to achieve the desired heater outlet temperature higher than normal heat fluxes are required. It has been noted that on catalyst bed skimming a significant portion of the material which has been fouling R 1401 is iron sulphide scale.
>
> 2.3.2 Thickness readings indicate a 30 MPY corrosion rate averaged over the past three years. The loss is suspected to be on the inner diameter. It is suspected that 95% of the loss occurred in the first

12 to 18 months and perhaps the 1/8" layer of iron sulphides may have slowed the corrosion rate. An assessment of the condition of the upper section would be useful. The current corrosion rate has been continuous since September 1994 and prior to this was lower. The corrosion loss will be examined further for a better understanding. It is also noteworthy that the new section of tubing, installed recently, has a current clean operating skin temperature of -200°F lower than the remaining fouled tubes. This indicates a significant insulating effect from the deposit layer.

2.3.3 Previous UOP recommendations and current industry design practice is to use 9 Cr as the material specification for NHT charge heaters.

A detailed review of operating conditions that considered both process side duty requirement, inlet heater design, radiant section design, fired duty of burners and heaters, erratic flames in radiant section, and inlet temperatures was carried out. The conclusions of the meeting were as follows:

3.1 It is evident that the tube failures are in part due to excessive heating of the lower tubes, passes no. 2 and no. 3, and subsequent creep failure.

3.2 The excessive heating may be due to:

3.2.1 Process flow maldistribution. If a lower flow rate or a lower liquid content occurs at passes no. 2 and no. 3, higher tube temperatures may be experienced. As no pass control or flow indication exists this is a difficult problem to diagnose.

3.2.2 Radiant section heat flux maldistribution. With passes no. 2 and no. 3 being in closer proximity to the burners radiant fluxes may be higher in the lower half of the radiant section.

3.2.3 Corrosion deposits on the inside diameter. Deposits will create an insulating layer. This is particularly significant given the current clean skin temperature - 200°F lower than the fouled tube temperatures.

3.3 The process side operating conditions have been within the design constraints of the heater.

3.4 Convection section fouling is adding significantly to excessive total radiant section heat fluxes and lower heater efficiencies.

3.5 Corrosion losses may be contributing to creep failure. The use of 5 Cr tube material my not be adequate for the current service.

3.6 Poor flame patterns will contribute to the tube overheating and are being hampered by:

3.6.1 Disrepair of the regeneration tile at all six burners.

3.6.2 The effects of high winds at the air registers.

A list of action to be taken was prepared:

Item	Action By	Recommendation	Ref.
4.1	QC Inspection	It was recommended that consideration be given to testing for first and second stage creep for tube life determination be made a part o the normal QC inspection shut down schedule	3.1
4.2	B. Walsh	A measurement of the convection section pass outlet temperatures may be useful in determining the existence of a flow maldistribution	3.2.1
4.3	T. Willis	A heat flux calculation is required separately for the upper and lower sections of the radiant section	3.2.2
4.4	T. Willis & Process Engineering	An assessment of improvements generated by permanent soot blowers is required	3.2.2
4.5	Process Engineering	A tube cleaning procedure will be provided by UOP	3.2.3

4.6	T. Willis	A new assessment of radiant and convection section duties is required	3.4
4.7	Process Engineering & QC Inspection	A high Temperature corrosion mechanism is a possibility and will be investigated further	3.5
4.8	QC Inspection	It is recommended that the tube metallurgy be upgraded from 5 Cr to 9 Cr. This recommendation is supported by UOP	3.5
4.9	QC Inspection	An understanding of the operating limits of 5 Cr versus 9 Cr are needed. These are with respect to H2S and H2 partial pressure, sulphur content, corrosion rates, temperature limits and pressure limits	3.5
4.10	B. Walsh	Related process condition will be investigated to determine possible contributing factors. Area suggested are the desalter operation, VBU naphtha, disulphide oil separator operation, tank 217 bottoms, thermal shocks, and organic chlorides. Testing of the tube side deposit for caustic soda may indicate a disulphide oil separator effect. Testing of the tube side deposit for caustic soda may indicate a disulphide oil separator effect.	3.5
4.11	Operations	Consider manual soot blowing	2.4.5
4.12	Process Engineering	Review the heat balance of the convection section to determine if it is possible that a flow imbalance is occurring. If so, determine a suitable means to correct. Consider installing FT's on the individual pass outlets.	3.2.1
4.13	T. Willis & Operations	A repair recommendation is required for regeneration tile and a window is required to make repairs.	3.6
4.14	T. Willis	Redesign and install burners for an "I" formation	3.2.2

4.15	T. Willis	Examine the convection section cold face design layout for improved method of removal for a clean out while shut down	2.4.5
4.16	Operations	A suitable wind break is required at H1401	3.6

Noted in the writing on the recommendations introduced at the Inquiry are the following words: "Retrieve sample from tubes cut out from last repair. Accelerated creep rupture test" (4.1). "Samples to be removed from upper pass next T/A" (4.1).

After this meeting, discussion appears to have been continued between staff in operations, heater group, senior management, and quality control. This discussion noted that a stable coke/sulfide scale had built up inside the tubes. This causes increased skin temperatures and eventual failure when operating at high heater duty and flow rate. As per UOP, the feed section of the naphtha hydro heater can be subject to accelerated corrosion whenever the feed sulphur levels and/or feed rate are increased over design.

> Over design higher feed sulfur result in more rapid high temperature sulfide attack in the high temperature sections. When this occurs, strong consideration should be given to changing the metallurgy of the transfer piping to and from the heater as well as the heater tubes. Corrosion inhibitors will not work in this area. The net effect of increased corrosion will be plugging of the reactor catalyst bed with corrosion products. The presence of cracked stock or gums in the feed will make this worse and can account for some of the heater tube scaling. UOP made the following recommendations to fix our problems. Ad just heater firing/het release in the lower section of heater. Consider rearranging burners in an "I" formation. Improve burner firing with new tip design, etc. A metallurgy upgrade to 9% chrome from 5% for all

furnace tube. Descale the tube during the next regeneration to reduce tube skin temperatures.

A copy of the relevant UOP procedure was exchanged between some staff and a request was made for an updated version. It was noted that the refinery needed to assess if any changes would be needed to the current operating direction of the refinery. In a memo from Ewan Atkinson, of senior management, to other staff dated 28th of November, 1995, the following comments were made:

1. Corrosion rates you need to discuss this with Curtis.

   The average over 3 years is 30 MPY, however, it looks like 95% of the loss took place in the first year or 18 months - November 94 to November 95.

   The 1/8" layer of FeS may have slowed it down. We also need information for the upper passes in the radian section for comparison.

2. Normal Process design load from the PFD is 25MM BTU at about 20,000 bpsd. The heater was oversized to handle up to a design load of 31MM BTU's (from my memory).

3. We also need to look at the design fired BTU's. If the heater efficiency is way off our Heat Flux will be high.

4. Convection section fouling and flue gas velocity maldistribution (higher velocities in the center of the box / More fouling on the outside coils will also contribute to poor thermal imbalance between passes.

5. Corrosion of 5 Chr. tube temperature limitations need to be investigated. Partial pressure of H_2S, H_2, and hydrocarbons. I believe UOP's temp limit is 650F, we are at 670F on the bottom passes. Bob/Curtis what improvement can we expect with 9 Chr?

6. Brian can you get a sample of the individual coil outlets and check for H_2S and Hydrogen %?

Recommendations:

1. Look into mixing and splitting of convection section outlet passes.

2. Look into relocating burners so that we have one in the bottom one in the middle and one firing to heat the top passes.

Rick, modeling using FRNC-5.

3. Improving CFE's by adding heat transfer area, via new bundles and/or extended surface tube in existing bundles.

4. Goal, to debottleneck to 26-30,000 bpsd

These memos clearly show that senior management was well aware of the potential risk of using higher sulphur content naphtha in the NHT, in particular H-1401. It is interesting to note that the final goal of Mr. Atkinson's memo was to increase the flow to 26-30,000 barrels bpsd.

Curtis Williams was instructed on 20 November 1996 to use 0.35 mol % H_2S for his evaluations and to set limits. This was based on current distillation (mol at 122) and a maximum 1000 ppmw sulphur in the feed. It was recommended that he use an inside tube temperature of 650° F maximum for 5% chrome and 700° F for 9% chrome to keep within a corrosion rate of 10 mpy.

Senior management, including the refinery manager, met on December 5, 1996 to review the contents of the Tube Failure Investigation report issued on December 3, 1996 (minutes of that meeting). The attendees at that meeting decided to subdivide the recommended action steps into:

Near Term - The next H 1401 outage, expected with 6 weeks
Immediate - to be done while in operation
Long Term - for further discussion and planning.

Sixteen recommendations were addressed.

Item	Action By	Action Step	Target
1	T. Willis & QC Inspection	Confirmation of the difference in skin temperatures of the old tubes and the newly installed tube. This is to affirm the negative effect of inner diameter scaling on tube skin temperature.	
2	B. Walsh & R. Jones	Develop a plan and procedure for descaling, chemical cleaning, the heater tubes. Immediate contact will be made with available resources. (Petrolite-Drew, ChemTec)	2-4 weeks
3	T. Willis	To resolve the radiant section heat flux maldistribution the burner arrangement will be revised. This will be initiated by designing and installing a single burner above the existing three. This is the highest priority item for near term actions.	Near Term
4	Maintenance	The installation of VFD's on the DCU HSR naphtha rundown has been improving the NHT feed temperature. Insulating the rundown and charge lines will add further benefits.	Long Term
5	Comment	A NHT rate reduction in combination with an Isomax naphtha sulphur guard will reduce H1401 load requirements.	Long Term
6	Comment	Fouling at the NHT feed effluent exchangers, E1401 A, B, C, will increase H1401 load requirements.	
7	T. Willis & QC Inspection	Replace panels in the convection section during the heater chemical cleaning with ones lined with castable refractory. This will allow for the later addition of soot blowers and will increase convection section duty by improving combustion gas flow.	Near Term

8	Operations	Plan a NHT shutdown during which items 2 and 7 will be conducted. During that time the Platformer will maintain operations at a reduced rate using tank 246 and Isomax naphtha. No heater entry is planned.	Near Term

The following is taken from the investigation report with a Target/Status column added.

Item	Action By	Recommendation	Ref.	Target/ Status
4.1	QC Inspection	It was recommended that consideration be given to testing for first and second stage creep for tube life determination be made a part of the normal QC inspection shut down schedule.	3.1	Long Term
4.2	B. Walsh	A measurement of the convection section pass outlet temperatures may be useful in determining the existence a flow maldistribution.	3.2.1	Immediate
4.3	T. Willis	A heat flux calculation is required separately for the upper and lower sections of the radiant section.	3.2.2	Immediate
4.4	T. Willis & Process Engineering	An assessment of improvements generated by permanent soot blowers is required.	3.2.2	Immediate
4.5	Process Engineering	A tube cleaning procedure will be provided by UOP.	3.2.3	Immediate
4.6	T. Willis	A new assessment of radiant and convection section duties is required.	3.4	Immediate
4.7	Process Engineering & QC Inspection	A high temperature corrosion mechanism is a possibility and will be investigated further.	3.5	Complete

4.8	QC Inspection	It is recommended that the tube metallurgy be upgraded from 5 Cr to 9 Cr. This recommendation is supported by UOP.	3.5	Long Term
4.9	QC Inspection	An understanding of the operating limits of 5 Cr versus 9 Cr and reeded. These are with respect to H_2S and H2 partial pressure, sulphur content, corrosion rates, temperature limits, and pressure limits.	3.5	Complete
4.10	B. Walsh	Related process conditions will be investigated to determine possible contributing factors. Area suggested are the desalter operation, VBU naphtha, disulphide oil separator operation, tank 217 bottoms, thermal shocks, and organic chlorides. Testing of the tube side deposit for caustic soda may indicate a disulphide oil separator effect. Testing of the tube side deposit for caustic soda may indicate a disulphide oil separator effect.	3.5	Immediate
4.11	Operations	Consider manual soot blowing.	2.4.5	Cancelled
4.12	Process Engineering	Review the heat balance of the convection section to determine if it is possible that a flow imbalance is occurring. If so, determine a suitable means to correct. Consider installing FT's on the individual pass outlets.	3.2.1	Immediate
4.13	T. Willis & Operations	A repair recommendation is required for regeneration tile and a window is required to make repairs.	3.6	Near Term
4.14	T. Willis	Redesign and instal burners for an "I" formation	3.2.2	Immediate
4.15	T. Willis	Examine the convection section cold face design layout for improved method of removal for a clean out while shut down.	2.4.5	Cancelled

4.16	Operations	A suitable wind break is required at H1401.	3.6	Complete

On December 11, 1996 Curtis Williams wrote to Bob Stacey confirming that ERA Technology would conduct six accelerated stress rupture tests on a sample of tube removed at the recent tube failure in heater 1401. The service would also include a metallographical examination after each test to determine failure mode. This data would then be used to calculate the rupture life at operating pressure.

The remainder of this letter clearly set out the concerns of Curtis Williams relating to the continuing operation of H1401 under the circumstances that existed at the time. He emphasizes that "If we wish to continue to successfully run this heater to the next scheduled shutdown without incident we need to establish exactly where we are in terms of the degree of creep damage already sustained." He noted that the current operating skin temperature had been somewhat arbitrarily set at 1000° F on the basis of information on new undamaged tubes, not on the older tubes. He emphasized at the end of this letter that "due to current uncertainty with allowable skin temperature in H1401 it is important that we move to make a decision on proceeding with the analysis as soon as possible."

> I think the information to be obtained in performing a remaining life assessment on the tubes in this heater would be invaluable. My reasoning stems primarily from my concerns for the current operating condition of this heater.
>
> Presently, tube skin temperature limitations have been set somewhat arbitrarily at 1000F. The set point is based in part on a remaining life fraction analysis which this department carried out

> using API guidelines. However, (and this has been stated before), the analysis is limited in that it is based on new, undamaged tubes. Our tubes are obviously no longer new and findings from our recent investigation into this heater suggest that our tubes have been subject to creep damage. If we wish to continue to successfully run this heater to the next scheduled shutdown without incident we need to establish exactly where we are in terms of the degree of creep damage already sustained. Once this ha been identified we can, with confidence, set the allowable maximum tube skin temperatures for this heater based on a desired operating life.
>
> Accelerated creep rupture testing such as that proposed by ERA technology will take 4 months to produce results. Due to current uncertainty with allowable tube skin temperatures in H-1401 it is important that we move to make a decision on proceeding with the analysis as soon as possible.

On the same day, Bob Stacey sent the request to the refinery manager, Dennis Huckaby. It was approved and on the 12th of March 1996, Curtis Williams sent the request to ERA Technology.

> Attached to that letter was the following background information:
>
> a. Inspection Reports for all major turnarounds and shutdowns due to tube failures starting from July 1993, when we experienced our first tube failure with this heater.
> b. All metallurgical consultants reports relating to heater tube metallurgy and failure investigations.
> c. Complete UT data for the south radiant wall tubes from 1987 to present. Note: This heater operated for approximately 2 years from 1974 to 1976. The refinery was then shutdown for 11 years. This heater was placed back in service in 1987. <u>I have no data from operation during the 70's</u>.
> d. A summary sketch of failure locations, dates and failure types.
> e. All available tube skin thermocouple readings.
> f. Detailed operational history from December 95 to present.
> g. Fired heater data sheet.
>
> The tube sample which was sent to you was removed from the heater during our repair of this past November. It's location has been identified on the summary sketch attached. You will note a thin deposit on the id. of

> the tube. This is believe to be corrosion product as a preliminary analysis showed it to be primarily 95% Iron Sulfide.
>
> I hope this data will be sufficient for your analysis. If you require additional information or clarification on anything that has been sent to you please call.

I note that this testing was not included in any of the 16 recommendations approved and actioned by the senior management on December 6, 1996. It also does not take into account the recommendations made by Curtis Williams in his November 25, 1996 H-1401 tube metallurgical evaluation where he had said:

> I would suggest, as a minimum, that samples be removed from the top pass radiant tubes for remaining life tube evaluation.

The tubes sent for analysis was tube 5, south wall, which was new in August 1993, not one of the older 7 to 9 tubes. However, I do again note, that written on the recommendations attached to the December 3 meeting are the words "4.1 samples to be removed from upper pass next T/A." This was not done between December 1996 and the date of the incident in March 1998.

Evidence tendered at the inquiry by engineers showed that sufficient data was available to the committee at that time, however, the committee did not have the ability to analyze it and it was inaccurate. The evidence indicated that if the committee had had the data before it that was available now (2002) that the committee may well have made a different decision concerning replacement of the insulation blanket and the insulation of new tubes (9 Chrome vs 5 Chrome). One engineer stated that if the recommendation made in 1996 relating to the insulation blanket and 9 chrome tubes had been carried out, the March 25, 1998 incident would probably not have occurred.

On December 17, 1996 T. Willis compared a detailed combustion review for H-1401. This addressed heat flux calculations for the three triangular burner pattern and the proposed three vertical burner pattern. From the detailed diagrams prepared by Mr. Willis, it can be seen that tubes 1 to 6 were located from 3' 6" inches (Tube 1) to 5' 6" (Tube 6) from the design flame envelope pattern. However, the observed pattern left the flame considerably closer to the tubes. This was not the designed flame pattern, and would have added to the heat flux in the heater. Further, tubes 7 to 9 inclusive were at a much further distance from the design flame envelope pattern of the triangular burner pattern. However, if the vertical burner pattern was followed, then tubes 7 to 9 came within four feet of the vertically installed burners thereby exposing them to increased heat flux and to greater flame impingement if there was an irregular flame pattern (different from design). The evidence of the operators at the inquiry indicated that the flames from the three vertical burners visibly and quite often went to the north and south side of the heater. The evidence presented at the inquiry showed that a flame pattern toward the south from the middle burner occurred as late as March 25, 1998. Jerome Kieley and Rick Connors were attempting to correct the burner when the accident occurred. The installation of the vertical burner system would reduce the heat flux to the lower tubes but increase the heat flux to the upper tubes, the older tubes, which included tube nine.

There was no general shutdown/turnaround scheduled for January 1997. However, heater 1401 was brought offline and shutdown on January 19, 1997 in order to facilitate acid wash of the interior of the tubes to remove the inner scale layer, replacement of the convection and roof panels and modification to the burners. In the process of shutting down the heater, a tube failure occurred at the anchorage pin location on tube 10. The anchor pin at the north end top outlet pass on the north radiant wall failed. The failure was a crack approximately 3/8 of inch running longitudinally in the toe of the weld which attached the anchoring pin to the tube at that location. The failure appears to have been the result of localized overstressing of the tube material which occurred as the normally fixed end of the heater coil was drawn in towards the heater. Visual inspection revealed mechanical damage to the tube within approximately one inch of the anchor pin. During the heater dryout, a more practical design of the pin attachment was prepared and a new external growth preventer pin was installed between January the 19th and 25th 1997. On January 25th as the heater was brought online or during the acid wash on January 23rd (which date is not clear from the evidence) the relocated pin sheared off again due to stress. However, this second incident did not cause any damage to the tube and the pin was again repaired in accordance with a procedure approved by the Department of Government Services and Lands of Newfoundland and Labrador. Evidence at the inquiry indicated that this pin crack was unrelated to the later failure of tube nine in March 1998.

Management at NARL viewed this incident with concern. This concern was obvious in an email from Larry Murphy to various employees at 2:27 a.m. January 26, 1997 in which he said:

> Gentleman, A call for assistance.
> As you are aware H1401, cell 1- upper pass outlet was damaged during the recent turn around. The pin holding the outlet header bent due to stress and cracked the weld where it joined at the tube. This was repaired and a new pin installed. During the heater dry out the new pin also bent due to stress. Due to a more practical design this time the weld at the pin broke and left the heater tube undamaged.
> This incident has cost us a lot, delaying the unit shutdown, extending the turnaround and delaying the unit restart.
> The potential for a major incident from this type of failure is high.
> I have issued an incident report and would appreciate hearing any thoughts you may have on what may have caused these failures, the steps we must take to prevent a recurrence and the extent to which other heaters in the plant are susceptible to similar failure.
> I will request an incident investigation meeting at a later date.
> Thanks. Larry

Due to the nature of the initial pin failure, an inspection of the tubes was carried out during the shutdown, in particular the direction of contraction of the tubes. It was observed that on tube no. 10 (outlet for the top pass, North Side) that the tube would move one to two inches east as evidenced by the wear marks on the underside of the tubes at the hanger furthest west. Wear marks at the remainder of the hanger locations were not as readily discernable. It was determined that this was likely the result of the coil being pinned to the east and forcing the cooling contraction eastward rather than westward as per design.

In addition, all the radiant tubes were inspected visually and checked for diametrical growth using OD calipers. A UT survey was conducted on all accessible radiant wall tubes and all accessible convection section tubes, and no thickness values were found to below retiring. Detailed readings were taken of the convection tubes at this time, however, only one reading was made on tube 9, north radiant wall, it being .226, a reduction from .252 in November 1996. There is no indication from the evidence as to where this measure was made on tube 9 or if it was at the same location as the measurement taken in November 1996. No evidence of creep damage or other mechanical defects were identified with the exception of one spot on tube no. 7, north wall, which appeared to have experienced some elevated temperatures. The area was closely checked for creep growth and hardness. The hardness value of that tube at the suspected hot spot was 160 BHN. Tube 4 was tested for hardness approximately ten inches from the heater corners and showed a range of values from 150 - 172 BHN. These values were within acceptable limits. However, no hardness testing was carried out on tube 9.

During this shutdown other work was carried out on heater 1401. Considerable work was carried out on the convection section: the heater panels, including the roof were replaced with pre-cast refractory liner (some void areas were left on the casing due to rough cutting) the buckstays (main structural supports) were lined with ceramic fibre blanket. Initially, it was proposed that the buckstays be lined with castable liner. Bob Stacey was concerned about the change of plans and in an email dated 21 January 1997 sent to senior management, engineering and maintenance, he stated that he did not support this change and said, “We all know the reliability of blanket in our heaters”. He also addressed the overall condition of the refractory in heater 1401 and in the inspection report dated 20 January 1997 he noted:

> The radiant walls, hips and end walls are lined with ceramic fibre blanket materials which was found to be in poor condition. Much of the hot face was observed to be damaged, with loose/hanging blanket observed in several locations in the hip section of the heater. No repairs were carried out during this turn around. Were the fibre blanket met the new refractory liner the gap (which resulted as the old blanket was tore away with the original panels) was packed with fibre blanket material.

This was further confirmed by R. Stacey in an email to C. Williams on the 27th of January 1997 where he said:

> INSPECTION OF THE RADIANT WALLS, HIPS, AND END WALLS [WHICH IS FULLY LINED WITH CERAMIC BLANKET] REVEAL THE BLANKET TO BE IN POOR CONDITION, HOT FACE BLANKET ON BOTH HIPS WAS RECOMMENDED FOR REPAIR/REPLACEMENT THIS T/A, HOWEVER WAS NOT DONE.

No evidence was presented at the inquiry as to why this change occurred. In the January 20th, 1997 inspection report R. Stacey noted that the heater skin casing, hips and end walls were observed to be in poor condition from the exterior with numerous holes in the casing throughout. Mr. Stacey added to the report in his email on January 27th where he said "Severe corrosion was noted in the skin casing ... it is recommended this skin casing be replaced next scheduled shutdown complete with castable refractory." From the evidence it is clear that the skin casing was not replaced at the next scheduled shutdown and in fact the castable refractory was only scheduled to be replaced in May 1998, after the incident occurred.

Holes in the casing effects the efficiency of the furnace. The influx of regular air into the furnace causes the furnace to be fired harder in order to keep up the temperatures in the heater so as to ensure proper tube temperature for heating the naphtha in the tubes. Wind is an environmental reality in Newfoundland. NARL recognized the potential impact of wind on furnace efficiency and installed a wind break to the east of heater 1401 in 1997. During this same shutdown, the burner alignment was changed from triangular to vertical. After the vertical burners were installed R. Stacey measured the burner deviation using a long level and tape. This showed a problem with the upper east burner. It was out by half an inch over the entire length and one inch over the tile diameter. R. Stacey observed the new burner cans from inside the heater and was of the opinion that they did not appear to be plumb. The east end top burner appeared to be looking at the roof tubes. Ted Willis in an email on the 23rd January 1997 noted that "I did not expect to have perfectly aligned burners because of the conditions of the shell". Whether he meant the present shape of the shell that resulted from the 1998 explosion or due to the present conditions of the shell casing is not clear from the evidence. Although not directly related to the tubes in heater 1401, Keith Ferguson in an email dated 26 of January 1997 to senior staff asked Joe Trahey to look at the supported steel work on heater 1402 which was installed after the explosion (1998) and do some checks to see if all is as it should be. This indicates that there was concern at senior management levels of NARL about the rebuild of 1402 carried out after the 1988 explosion. One has to ask whether the same concerns should have been apparent with relation to heater 1401 for the same reason? No evidence was presented at the inquiry that the problem identified by R. Stacey was corrected at that time or later. An April 1997 letter from Born, the designers of the furnace, confirmed that there was burner misalignment at that time, three months later.

When the new panels were installed in the convection section, they were designed to allow for later installation of soot blowers (installed in October 1997 during a scheduled shutdown). These devices are installed in order to be used to remove deposits from the convection section tubes while the heater is on operation, thereby improving the heat absorption of the tubes and thus reducing the load on the lower convection section tubes. This in turn will require less heating in the radiant section as it would not have to be run as hard.

As per recommendation 4. 5 of the December 3, 1996 meeting, Serv Tech of Houston carried out an acid wash of heater 1401 in order to attempt to remove any interior scale layers in the tubes. The acid wash, hydrochloric acid, was carried out in accordance with a procedure set out by UOP, using inhibited hydrochloric acid. A very important part of the recommended UOP procedure required that after the application of the acid wash to descale the tubes a neutralizing solution be put into the tubes. The neutralizing solution was not, however, applied to the tubes in heater 1401 after the acid wash in January of 1997, only water was used to wash the tubes. In the A.D. Tupper report concerning the March 1998 incident it is stated that “common sense would dictate that any unneutralized acid left in the descaled tubes would tend to attack the freshly exposed metal, and further reduce the wall thickness.” R. Stacey in his

January 20th 1997 report reported that "the wash carried out in accordance with the UOP procedures with the exception that upon completion of the acid wash the tubes were water flushed without performing a soda ash wash." Lionel Roberts in an email to R. Stacey on 23rd January 1997 recognized this problem before the wash was applied and said "David Qui has informed me that after the acid wash is completed the tubes will be water flushed only (no soda ash wash) this is contrary to UOP procedure which clearly states 'water flush the tubes before and after the neutralizing with soda ash and after detergent and remove all traces of acid and neutralizers." Regardless of this very valid observation by Mr. Roberts, no neutralizing fluid was used to after the acid wash. No adequate explanation for this decision and action was given at the inquiry. When the clear direction from UOP and the questioning by Stacey and Roberts is considered, it has to be asked, why was such a decision made and at what level?

During the January 1997 shutdown an inspection found that the skin thermocouples installed on 1401 in the October 1996 shutdown where not designed for heater 1401 and had been bent and modified in order to fit the heater. They were not changed during the shutdown and R. Stacey recommended on the 27th January 1997 that they be changed at the next turnaround as per T. Willis recommendation. In addition to the work and maintenance carried out on heater 1401 during this shutdown, the inspection report recommended the following work be carried out:

a. Replace all radiant, hip and end wall panels with new panels complete with precast refractory liner. Install refractory on heater structural support beams as well.

b. Purchase 40 new wall hangars for next T/A. Recommend upgraded metallurgy to ASTM A560, (50Cr/50Ni with Cb stabilizer). Work order 12968 posted.

c. An engineering evaluation of the suitability of current tube anchors and associated structure is required.

Subsequent to the descaling (acid wash) carried out in January 1997, the tube skin temperatures on 1401 decreased significantly.

The evidence shows that Curtis Williams followed up with ERA in March and Roger Newman of Born Canada carried out a site visit on April 20th, 1997. Mr. Newman prepared a heater inspection report on heater 1401 and 1402 and that report stated partly:

> NORTH ATLANTIC REFINERY INC.,
> COME-BY-CHANCE, NEWFOUNDLAND
>
> HEATER INSPECTION
>
> SUNDAY, APRIL 20, 1997
>
> On Sunday, April 20, 1997, I met with Bob Stacey, and had a brief discussion on which Heaters need to be looked at, and their areas of concern. These Heaters are as follows:
>
> Heater 1402:
>
> A Bowed Outlet on the last tube. This is probably caused by differential expansion between the two passes.

Fireflys: This is caused by incomplete atomisation of the Fuel Oil

There are several areas of damaged Ceramic Fibre Refractory. This needs to be replaced with castable due to the Vanadium the fuel oil.

The In-balance in the Heater Temperature, should be better balanced. The upper box is hotter than the lower box.

Heater 1401:

The Stop Pin has failed on the outlet Tube, again due to uneven expansion of the Outlet Tubes. In this instance, the Outlet Piping System should be inspected to ensure that the heater is not taking the full load of the piping and acting as an Anchor Stop.

The Refractory is loose. There are several areas, apart from those that are falling off, that are eroded.

There are Hot Spots on the Coils. This is primarily due to Heavy Ash build-up.

There is no draft in the Heater. This may be caused by, being over fired, too much excess air, or lack of damper control.

The Burner has been relocated. The two Burners at each end of the Heater have been replaced with one Burner placed higher up on the box. If the Burners are not balanced correctly, this will cause the box to be hotter at the top.

General Notes:

Burners: the Burners are the starting point of the operation. Improvement has been made, and many of the Burners are operating better than my they were on my previous visit. There are many Burners that should be replaced since they are old, inefficient and eroded. The main issue here however, is that all of the Burners should be turned on operated at the same load s each other. This applies to both the Air and the Fuel settings. When turndown is needed, they should all be turned down together, not individually. Special care needs to be taken to achieve batter atomisation.

Refractory: As a start point, all Ceramic Fibre should be replaced with Castable type. Where Refractory has fallen, especially behind

> the Tubes, this should be removed, and replaced if possible. Refractory that is lodged behind the Tubes impedes the flow of recirculating flue gases down the back side of the Coils. If this is not removed, the front side overheats and results in the Tubes bowing.
>
> Piping: The external Manifolds to the Heater should be checked for flexibility and movement. There are several Manifolds which have "Bound-Up", and thus the expansion has been forced in the Firebox. Hence Sheared pins and "Rippled" Tubes. As a guideline, you may use the allowable loads in AP160.
>
> Reformer: The following is a brief list of suggested repairs/modifications:
>
> Ensure better Catalyst loading procedures are followed, particularly removal of old Catalyst and the installation of a new one. Check Delta P.
> Install new Refasil Cloth around Tube Inlets. The lack of this seal is allowing air infiltration, which is allowing/causing after burn.
> Add a return or re-size Fuel Gas Inlet Header. A lack of this is causing in-balance of fuel to each Burner.
> Repair Waste Heat Boiler Refractory.
> Realign Burners. Some are now impinging on Refractory Brickwalls.
> Refractory repairs are needed.
> Cell Firing rates. These need to be better balanced.
> Burner Balancing is need, both Air and Fuel settings.

No evidence was presented in the Inquiry to show that the issues raised in the report were immediately dealt with or given any priority, even though many of his comments and findings merely confirm matters already within the knowledge of the employees of NARL.

It appears from the evidence that the receipt of the ERA technology report by NARL in June 1997 subjectively satisfied NARL of the causes of the previous tube failures and estimated a significant remaining life for the tubes in heater 1401. ERA very carefully explained that its report was based on the operational and tube thickness evidence provided by NARL and an analysis of the section of ex-service tube. It carefully noted that given the absence of recorded operating temperatures over the majority of the tube life span, the conclusions of the report were qualified principally with respect to temperature. Further, the report is subject to the absence of local overheating, the accuracy of NARL thickness measurements and a certain level of corrosion from the type of feed being used. The scope of the ERA report analysis included:

1. Accelerated creep rupture testing of a sample to determine the actual creep rupture strength of the tube material heat.
2. Metallographic evaluation of a through-wall tube specimen to evaluate the possibility of creep damage (cavities, microcracks).
3. A remaining life assessment in accordance with API 530 and ERA standard procedure.
4. That ERA provide recommendations for alternative tubing material selections.

NARL had provided ERA with the following detailed information:

1. The design parameters of heater 1401.
2. Temperatures recorded by Gayesco thermocouples January - April 1996.
3. Random feed outlet temperatures from December 11, 1995 to October 8, 1996.
4. Tube skin temperatures measured by knife edge thermocouples from 22 June 1995 to January 1, 1996.

5. Random ultrasonic thickness measurements of selected tubes June 1987 to November 1996 (no evidence that tube nine was included).

Due to the large temperature differences between two and four above, ERA used the feed outlet temperature as being more reliable and estimated the tube skin temperature by adding 200° F to the maximum feed outlet temperature. ERA then estimated the temperatures to be used in their analysis. In addition, ERA "assumed" that the thickness measurements were determined on the tube that had been in service over the entire life of the heater (12 years)". They calculated the corrosion rate at 3.3 mils per year, but due to uncertainties in the thickness readings the corrosion rates was rounded up to 5 mils per year.

The tube provided (a 1993 installed tube) was analyzed and a thick oxide layer was observed on the outside diameter nearest the burners. A thick layer of corrosion product was readily visible that was high in sulphur and the obvious conclusion was a corrosion medium of sulfidation. ERA stated "both the OD oxide/deposit and the ID sulfide layer represent thermal barriers that require higher tube temperatures for the same charge outlet temperature. This being said, the metallurgical and chemical analysis showed the wall thickness of the tube sample within the requirements. Further, the accelerated creep and elastic yield analysis where within the standards set by API 530." Taking this information into account, ERA conducted a remaining life assessment of the tubes. Using certain temperatures, estimated due to the uncertainty of the tube operating temperatures provided by NARL, ERA provided a table of expected tube replacement. In the absence of creep and overheating tube failure will take place by elastic yielding if the tube wall is thinned by internal corrosion or external oxidation to a thickness where the tube can no longer support the internal pressure. ERA, with qualifications, concluded:

1. All available evidence, including consultant's failure analysis reports, heater service history, operating parameters, metallographic evaluation of a through-thickness tube sample, and the results of accelerated creep testing substantiate the conclusion that past failures of the radiant tubes in heater H-1401 are the result of either short term or persistent (long-term) local overheating. No significant evidence of creep failure in the absence of local overheating was observed. The implication of these observations is that the tubes possess significant remaining life if local overheating can be controlled.
2. The extent of remaining life, in the absence of local overheating, will depend strongly on the tube operating temperature. At tube skin temperatures of 900° F and higher, creep failures will predominate and tube life will be shortened. Tubes that possess a wall thickness less than that assumed in Tables 5 through 10 (e.g., 0.193 inches in 1997) will clearly have a shorter remaining life than that estimated by this analysis.
3. Despite current literature recommendations for material selection, 5 Cr1/2Mo appears to have adequate corrosion resistance in this

environment if the tube thickness measurements provided by North Atlantic are accurate.

4. The advantage of accelerated creep rupture testing is clearly shown by this analysis. If the actual creep strength of the tubes had not been determined and therefore the API 530 minimum strength curve was assumed, a non-conservative estimate of th tube remaining life would have resulted.

The problem with these conclusions include:

1. The metallurgical and chemical analysis were based on a tube installed in 1993 not during the whole operational life of the heater (tube 7 to 9 inclusive)
2. Very few skin and knife edge thermal couples were installed in heater 1401 and the evidence shows from infrared testing that these were not accurate.
3. The evidence at the inquiry points to consistent flame impingement and heat flux on the tubes (in particular the effect of reconfiguration of the burners on tubes seven and nine)
4. ERA was not informed of the acid wash problem at the tube they analyzed was not subjected to that situation in 1997
5. The analysis and conclusions of ERA were based on a certain sulphur level not being exceeded. The evidence presented at the inquiry shows an increase in viscosity and sulphur content in the feed for many months before the March 1998 incident.

6. Infrared measurements showed a higher temperature than those reported by thermal couple measurements. The infrared measurement indicated skin temperatures of 1000 -1100° F. These are above the refineries recommended operational limit of 900°F, and higher than the design "maximum skin temperature", and higher than the test temperatures used by ERA (maximum set at 975°F) to determine the remaining life of the tubes.

ERA carefully worded its recommendations. The recommendations in the ERA report were not numbered, however, I have added numbers for discussion purposes.

1. Local overheating, both short-term and persistent, must be controlled if the desired tube service lives are to achieved. Burner type, design and orientation, and furnaced operating controls should be reviewed.

2. In order to maximize service life, the tubes in naphtha hydrobon charge heater H-1401 should be operated at a skin temperature of 900°F or lower depending on process requirements.

3. Given the uncertainty in the measured temperatures, it is strongly recommended that the tube operating temperatures be verified by pyrometric measurement. If pyrometry indicates that the actual temperatures are significantly different from the assessment temperatures used in this analysis, refined calculations can be performed (under the scope of this contract) upon supplying such temperatures to ERA Technology.

4. The deposit and oxide layer on the O.D. of the heater tubes should be removed at each heater shutdown by sandblasting. This will allow the tubes to be operated at a relatively lower temperature for the same charge outlet temperature.

5. Upgrading the tube material from 5Cr to 9Cr or 12Cr is recommended if the corrosion rate increases much beyond the current assumed rate of 5 mils per year.

6. Failures of tubes previously damaged by fires or local overheating may take place prior to the recommended tube replacement years provided in this analysis. It would be prudent to keep several new tube lengths on hand should replacement become necessary. *On-site inspection and replication to determine which tubes are prone to premature failure due to prior damage is strongly recommended.* ERA Technology will provide inspection and replication services if so requested.

Taking into account all the evidence received at the inquiry and after review of the documentation I make the following observations:

1. We know from the evidence presented at the inquiry that the flame impingement, after burning, ash build-up on the tubes, and heat flux continued in heater 1401 after the ERA report. These caused local overheating of the tubes. It was never fully controlled and persisted until March 1998. The coking off problems that often cause the flames to shoot sideways and contact the tubes became especially prevalent in the months and weeks leading up to the March 25, especially given the quality of the fuel being processed. We know that from the January 1997 inspection and the Born heater inspection in April 1997 that if the burners are not properly balanced this can cause the heater box to be hotter at the top. We know that in April 1997 there was no draft in the heater. All these

items could have materially affected the life of the tubes something recognized by the ERA report.

2/3 The measured tube operating temperatures were not verified by pyrometric measurement. The evidence presented at the inquiry indicated that the skin temperatures rendered by infrared measurements were higher than those indicated in the attached measuring devices. No evidence was presented to show that these infrared measurements were forwarded to ERA to refine their calculations.

4. There is no evidence that the deposit and oxide layer were removed by sandblasting in each heater shutdown.

5. Walsh, Stacey and Williams had all recommended that the 5Cr tube be upgraded to 9Cr - 1 Mo.

6. Curtis Williams acknowledged at the Inquiry that "there is a considerable factor of error in my calculations in determining the pre 1998 corrosion rates.

The ERA reports notes that the current material recommendations for refining equipment operating in environments containing hydrogen + hydrocarbon + hydrogen and hydrogen sulphide of greater than 0.01 mol % at temperatures greater than 550°F is type 321 or 347 stainless steel. With sulphur content in heater 1401 fuel ranging up to 1000 ppmw (1% of weight) that environment would require the use of 321/347 stainless steel if the current recommendations were applied. In spite of this, the recommendation of ERA is that 5Cr1/2 mol low alloy steel appears to be adequate for heater 1401. This conclusion is based on the assumption that the ultrasonic measurements are accurate. ERA opined that there was no reason, at that time, to automatically disbelieve the thickness measurements despite the noted abnormalities. ERA then made a crucial comment "In fact, micrometer measurements of the test tube indicated a remaining wall thickness of 0.238 inches". However, this was a 1993 tube not a tube originally installed and used during the whole life of the heater. ERA concluded that upgrading of the tube would not have a beneficial effect in terms of restricting the effect of local overheating and they referred to the analysis of the analyzed tube to support this opinion. However, ERA then said:

> Upgrading the tube material from 5Cr to 9Cr or 12Cr will, however, have a beneficial effect on the corrosion resistance. Given that the current operating parameters and feed composition will continue into the future, the use of a stainless steel would not appear to be warranted. If corrosion rates increase in the future, upgrading the tube material to 9Cr or 12Cr should be considered. At corrosion rates of 10 mils per year or higher tubes fail prematurely by wall thinning (Table 13).

We know now that NARL staff knew well before March 1998 of the internal corrosion possibilities due to the type of fuel they were processing at the refinery. No evidence was presented at the inquiry that a detailed corrosion rate on the tubes of 1401 was carried out between January 1997 and March 1998.

Several of the comments I have made concerning the ERA report could be called after-the-fact armchair reflection. I acknowledge that some of the relevant information only arose after the ERA report was presented. NARL has submitted that the ERA report allowed it to reasonably conclude that if isolated overheating of the tubes was controlled then the tubes had a significant remaining life. If the flame impingement and the heat flux problems had been controlled and if the type of feed had not changed that may well have been a reasonable conclusion. However, that is not what the evidence indicates. It may be said that NARL "relied" on the ERA report and it caused them to believe that the tubes in heater 1401 still had a significant remaining life. However, the limitations and qualifications of the ERA report were not kept in the mind of NARL and ERA's observations and recommendations were not followed so as to make the submissions of NARL on this matter reasonable. The circumstances and facts that existed at the NARL refinery in 1997 to 1998 should have caused the staff to be more careful in relying on the ERA report. I believe it gave NARL a false sense of security, which was not based on a reasonable assessment of the facts and events that occurred after January 1, 1997. The ERA report was circulated to all senior management, engineering, maintenance, safety and production staff at NARL on the 18th of June 1997. The memorandum circulated in the report stated:

> Attached is a detailed Remaining Life Assessment of the tubes in our Naphtha Hydrobon Charge Heater, H-1401. The investigation was conducted by ERA Technology out of Houston Texas and is based on accumulated data on our heater and the testing of an actual tube sample removed from the heater during the November 1996 shutdown
>
> There are several key points of note:
>
> 1. Table 11, page 16, lists the expected year of tube replacement based on tube skin temperatures. The sensitivity of the tubes to creep failure based on minor temperature increases above 900F should be noted.

2. ERA used tube skin temperatures based on process outlet temperatures. They felt that the data collected using the skin thermocouples was inaccurate. They recommended using Pyrometry to collect accurate skin temperature data. I am following up on this item with them.

3. ERA confirmed our past investigations into tube failures in this heater citing local overheating to be the primary cause of failure.

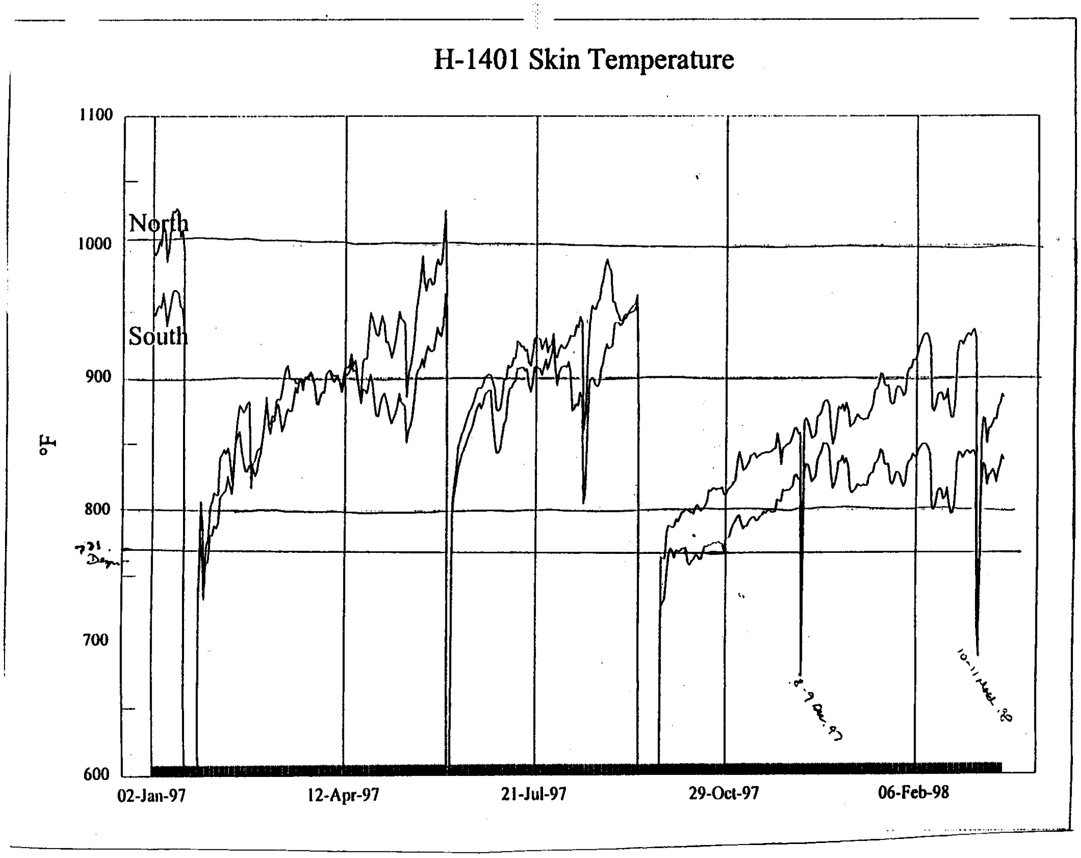
The report contains a number of other conclusions/observations and will be circulated accordingly for review and comment as per the distribution list below.

Very few of the documents tendered in evidence by NARL to the Inquiry for the period between June 1997 and March 1998 even mentioned the ERA report or any of its recommendations.

Heater 1401 continued online during the summer of 1997. Some work was performed on the unit: bolts and weld seams were replaced on the northeast end (May) and a new guide pin was installed on an inlet tube (July). A planned shutdown of the refinery took place in September 1997. The operation records at NARL show that subsequent to the descaling (acid wash) carried out on heater 1401 between the 20th and 23rd of January 1997, the tube skin temperatures decreased significantly. The skin temperatures then increased with time and operation until it peaked at 1000-1040°F. The scale was removed on 4th and 5th of June 1997 mechanically by steam injection (spalling) during the shutdown. After the spalling the skin temperature was reduced but again increased and as the temperature had risen to almost 1000°F by September, another steam spalling and a chemical clean was carried out on heater 1401 between the 12th to the 22nd

September 1997. Thereafter, the skin temperatures again rose to approximately 950° just before the middle of March 1998.

OHS 3 TAB. 9



From January 1, 1997 until March 25, 1998, the tubes on the north radiant wall consistently had a higher skin tube temperature than those on the south radiant wall of heater 1401.

In an internal memo from M. Popovic to F. Hallett (a member of the heater group) on July 7, 1997, Mr. Popovic informed the NARL heater team that the process and combustion side of heater 1401 had been reviewed and he noted that “the outlets tubes are bowing” and later in the same memo he further stated “the outlets tubes were bowed especially number nine rows”. (Tube 9 is the outlet tube on the bottom pass of the north side of the radiant section, the tube that failed in March 1998). This is not the first observed bowing in the tubes at the nine level. In an inspection report dated September 20th, 1993, it was noted “tube 9 on south wall appears to have a slightly larger bow than previous”. Robert Stacey testified that tube 9, north wall, was “slightly bowed” in 1988 explosion, however, it was straightened using an acceptable procedure (using a jury rig and bending it back). Popovic in the July 7, 1997 memo recommended that “Outlet tubes are bowing and should be monitored closely” and in the recommendations he noted that “at this firing rate it is uncertain to run the heaters since T/A”. The bowing of tubes is an indication of stress on the tubes. It is a condition that should not be allowed to occur let alone continue. No evidence was tendered at the inquiry to show that F. Hallett passed on this information to any other staff or to the heater group or that anyone in the heater group passed on this information. In fact, it appears not to have gone beyond the heater group. The whole tone of this particular memo points to the recognition by that group of the poor physical condition of heaters 1401 and 1402 yet in order to maximize efficiency the group allowed 1401 to be continued to be run at a high firing rate. The memo clearly indicates problems that were occurring at the high rate of firing of heater 1401 in July 1997, yet there is no indication that any immediate corrective action was taken to address the situation other than a slight reduction in the feed rate (22,800 barrels to 22,400 barrels per day) and the RFO pressure was reduced from 90 psig to 88 psig. The memo also noted that the RFO temperature thermometer showed an erroneous reading and should be replaced. It showed 350° (whereas 450° was required for proper atomization). In spite of the situation, hip temperature was increased from 1586°F to 1612°F shortly thereafter. No testing of the tubes was carried out after the July bowing was observed. The "bowing tubes" continued to occur. On December 10, 1997 the Operations Department heater logsheet states "bowing tubes, lots halls N/S walls E/W walls ... lots of air being pulled in through holes in heater". Again no evidence was tendered that the bowing was addressed at that time by the heater group or any other staff. One senior operator testified at the inquiry that "we knew the heater was not in really good operating condition and was coming to the end of its life ... there were several big bends of bows in the tubes in the area of the breach, these were my biggest concern, they were there for quite some time and readily apparent and obvious if you looked at it. This came up daily with other operators and was brought up with our supervisor, definitely Gary O'Connor ... brought up for at least a year by me ... the bend was six to twelve inches over three to six feet and it was obvious if you looked at it. This was an abnormal condition, pipes bent not what's supposed to by manufacturer and this could cause stress on the pipes."

At the Inquiry, a senior member of the heater group testified that he was not personally aware of the tube life data analysis performed at H1401. Further, he stated that the heater group was not responsible for ensuring the proper condition of the heater or that the heater was operating within the recommendation of the Walsh group (the Walsh report on heater carried out in

1996), that was the responsibility of operations. This is startling evidence from a senior engineer whose responsibility was to maximize the efficiency of the furnace and raises grave concerns especially as it is considered with other documentary evidence presented to the Inquiry in which the heater group actually prepared the proposed scope of work to be done on heater 1401 during the May 1998 scheduled shutdown. This is an example of the lack of communication between planners and the operators and safety departments at NARL which appears to have been prevalent before March 1998.

No residual or repair work was carried out on heater 1401 during the September 1997 shutdown. However, steam spalling was carried out which I have already made reference to. Soot blowers were installed in heater 1401 in October 1997 to permit removal of soot build-up on the convection tubes of that heater. The evidence indicates that this was due to extensive fouling in the convection section of heater 1401, present when the soot blowers were commissioned, thereafter there was no record of any significant effect on the heater's performance. (M. Popovic memo March 26, 1998) even though the heater group expected to see improvement. "Normal cleaning" of the tubes was scheduled for the May 1998 turnaround. Operators continued to use the soot blowers up to and including March 25, 1998. Removal of soot from the exterior of the tubes in the convection section should cause the radiant section to be fired less in order to raise the hip naphtha temperature, thereby putting less strain on the tubes in the radiant section of the heater.

The evidence tendered at the inquiry also indicated other continuing problems with heater 1401 and upline equipment at this time.

Fouling in the upline combined feed exchangers caused the naphtha feed not to be vaporized properly before entering heater 1401. Hence, some liquid entered the convection section of the heater. This in turn caused an imbalance of flow through the passes in the heater. This imbalance required that the heater had to be fired harder in order to vaporize the feed in order for it to reach the required outlet temperature. This could cause high or over firing. These upline exchangers were cleaned in the fall of 1997.

Holes in the external shell skin of heater 1401 allowed tramp air to be introduced into the heater, upsetting the air balance and thereby decreasing the efficiency of the heater. The tramp air problem had existed for some time. NARL erected a barrier to the west of heater 1401 in 1997 to cut down the wind effect and tramp air entry into heater 1401.

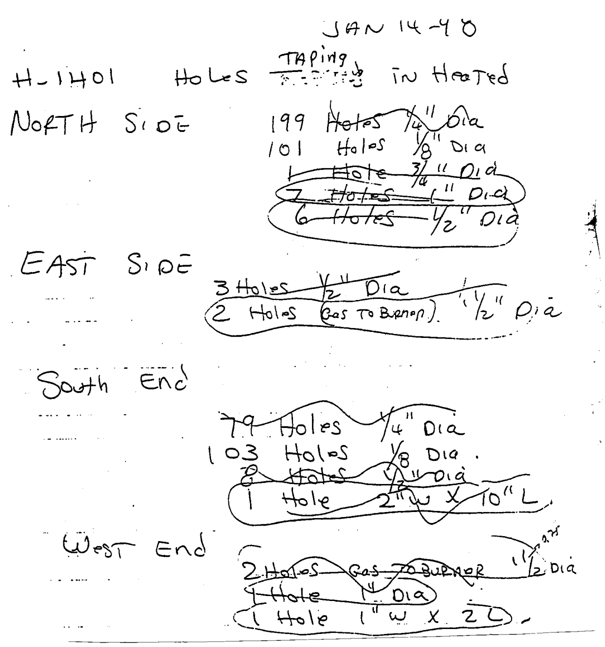
The evidence indicates that this tramp air did have some significant effect on the efficiency of the heater. The design parameters of heater 1401 permits 4.5% (excess air 25%) excess oxygen. Evidence presented at the inquiry indicates that the RFO and heater conditions set by UOP recommended up to 6% (30% excess air). From May 1997 to April 1998 excess oxygen ranged from 4.9% to 6.1% (M. Popovic), however, a review of the operators records shows that on occasion it reached 8.4% (January 14, 1998). It is clear from the evidence that the tramp air could cause problems to the operation of the heater. The heaters have to be constantly adjusted for the additional air.

The July 7, 1997 Operations Department heater logsheet noted:

> South walls poor shape over heat (warped). Everywhere, corrosion very bad. North side walls holes everywhere, bad corrosion. Hip warping hot areas, both sides. Oil temp 342°F.

In the December 10, 1997 heater logsheet it stated "lots of air being pulled in through holes in heater " ... "heater in poor shape, blanket off wall, bowing tubes, lots holes in north/south walls east west walls". In fact at that time the arch temperature was 1580° whereas the design was only 1554° and the target being 1510°F. This is a further indication of how hard the heater was being run at that time.

The January 14, 1998 heater logsheet states "hundreds of holes in hip and radiant sections." Attached to that report was a list of all the holes. This list was prepared so as to ensure taping with "duct tape" of the holes shown in an actual diagram..


JAN 14-98

H-1401 Holes TAPING in Heater

NORTH SIDE
199 ~~Holes~~ 1/4" Dia
101 Holes 1/8" Dia
~~1 Hole 3/4" Dia~~
~~7 Holes~~ 1" Dia
~~6 Holes~~ 1/2" Dia

EAST SIDE
~~3 Holes 1/2" Dia~~
2 Holes (Gas To Burner). 1 1/2" Dia

South End
~~79 Holes 1/4" Dia~~
103 Holes 1/8 Dia.
~~8 Holes 1/2" Dia~~
1 Hole 2" W X 10" L.

West End
~~2 Holes Gas To BURNER~~ 1 1/2 Dia
~~1 Hole~~ 1" Dia
1 Hole 1" W X 2 L.

It appears that these holes were taped. Employees at NARL were concerned about taping the holes so senior management began the process by personally putting the tape on the holes. Evidence at the inquiry indicates that a special heat resistant aluminum tape was used to cover the holes. This procedure appears to be acceptable in the industry. After the holes were covered the efficiency of the furnace appeared to increase.

It is clear that management at NARL was aware of the ongoing problems and concerns with heater 1401 and other heaters at the refinery at this time. The heater group set up in 1996 was originally formed to aid operations in reducing the fireside load on the heaters and to optimize heat distribution.

By December 12, 1997 the heater group prepared a preliminary scope of work for heater 1401 and 1402 to be carried out during the scheduled May 1998 shutdown. In a letter of that date M. Popovic sets out the proposed work on heaters 1401 and 1402 for the May 1998 shutdown.

NHT Shutdown Heater H-1401 & H-1402 Scope of Work

(Preliminary)

1. General

> In May 1998 the NHT will be shutdown for NHT Reactor R-1401 skim and repair work at the heaters H-1401 and H-1402. This work should be done in a 7 day shutdown, a five (5) day maintenance work.
>
> Ths scope is based on the heaters regular monitoring data and observation of physical conditions. The intend is to restore the heaters suitable for another run. Both heaters should be done simultaneously.

2. Shutdown Work

- documentation review, and preparing drawings for fabrication of new panels with refractory anchors and 3 ½" refractory.

- purchase bridge wall and stack thermowells and thermocouples

- purchase the new tube skin thermocouples

- opening the convection section and cleaning convection tubes. Final cleaning will be manually.

- cleaning and adjust the baffles

- inspection the stack dampers. Verify clearances around damper blades and blade position relative to outside indication.

- inspection the ducts, transition and stack section castable refractory and repair eventually

- remove the fibre blanket and the fibre pins by ground off on the panels in good shape

- cleaning / vacuum the fire boxes.

- erect scaffolding full length of the heater from floor to shock tubes and rig lighting.

- install castable refractory on the buckstays instead of fibre blanket in convection section

- Replace fibre blanket with 3 ½" castable refractory in both heaters. Presently it is only at the End walls burners level.

- Burners inspection and adjustment from inside. Replacing broken tiles on two burners H-1402

- Install the skin thermocouples per the sketch. Wiring will be after s/d.

- Install the pilot gas piping at the Aux. Burner East End.

- Clean the radiant tubes with steel scrapers

- install the TI, DG, 1 " 3000# cplg. sampling points as per original drawings.

- Remove scaffold.

The most important work scheduled for heater 1401 was replacement of the casing panel and insulation with new steel panels lined with castable refractory and installing new thermocouples. No provision was made to upgrade the tubing or hangars, take any samples of tubes for detailed analysis or address the ongoing bowing of tubes. No evidence was tendered as to the work to be performed on heater 1401 by the QC Department at NARL during the planned May 1998 shutdown. It is "presumed" that the regular inspection of tubes would have been carried out using UT or other testing procedures and that such would have been performed within the opened heater on all accessible tubes.

The Come-By-Chance refinery is designed to refine heavy crude oil. The burners that provide the heat in heater 1401 are fired by heavy refinery fuel oil. It is critical that the viscosity of the fuel at the burner tip is adequate so as to ensure good atomization and combustion of the fuel.

The temperature of the fuel oil was controlled by a black oil heater (H3501). The recorded viscosity for oil fired heaters of this type was 45 C.S (centa stokes). The fuel oil comes from refinery crude oil. The type of crude oil being refined effects the outlet temperature of the black oil heater. The outlet temperature of that heater is supposed to be controlled in order to ensure that the outlet temperature results in a viscosity of 45 CS. Due to the type of crude being refined at Come-By-Chance in 1997-1998, the viscosity significantly increased during two periods. From May to September 1997 and from December 1997 until March 1998. In these periods, the viscosity (at 100°C) increased from 2000-5000

CS to 10000-47000 CS. In order to achieve a viscosity at the burner of 45 CS the temperature of the fuel oil must be increased from around 195-210°C to 240°C when firing heavier fuels. NARL records show that the fuel oil temperature coming into heater 1401 did not exceed 222°C during 1997-1998, 20% lower than the required inlet temperature. It should be noted that one of the fuel oil tanks (T-641) used to supply fuel to the refinery furnaces was limited by its design as regards the maximum fuel temperature it could supply. It is critical that the viscosity of the fuel oil at the burner tips is adequate so as to achieve proper atomization and combustion. Shell International Oil Products (SIOP) advised refineries to use viscosity of 20 CS. For steam atomized burners, SIOP allows a somewhat higher value but only in the case where steam atomization is high and the burners are of the forced draft principle. For natural draft burners, as installed in heater 1401, it is advised and recommended by SIOP that 20 CS be used. NARL records show that the temperature of the RFO coming into heater 1401 did not exceed 218°C (450°F) during most of 1997 and 1998 and that the temperature at the burner dropped by 7° from the inlet temperature. The resultant temperature at the burner results in a viscosity of around 100 CS for the type of heavy fuel oil processed by NARL from May to September 1997 and December 1997 to March 1998. This is too low and it had two prime effects:

1. Increased the peak influx as the flames are more luminous, causing the radiant heat to increase above design and as a result the tube wall/skin temperatures will increase above design.

2. Produces coking and burner flame instability which caused the flame to get closer to the tubes than intended, this again creates extra heat on the tube surface and skin.

The naphtha feed to the NHT comes from two units: the CDU and the Hydro Cracker (HC). In the course of 1997 the composition of the feed from these units to heater 1401 was changed. Before September 1997 the ratio of feed from the CDU and HC was 1:1. However, after the installation of a sulphur guard bed in September 1997 it became 1:5 respectively.

The consequence of this change is that less clean feed (from the HC) was available and at the same time more product (from the CDV) with a potential fouling nature were added. This increased sulphur content of the feed (H_2S) would have a major effect on the corrosion rate in the tubes.

The evidence indicates that early in 1998 several employees of NARL who worked with the NHT unit were aware of some or all these concerns and became alarmed as to the condition of heater 1401. Several operators and other employees testified at the inquiry that they were concerned about the condition of heater 1401 and it had a reputation for being unreliable. The evidence of the employees at the inquiry varied from heater 1401 being an extremely dangerous place to work to being uncomfortable and cautious when around the heater. In the days leading up to the March 25 incident, it is clear that the burners and burner guns in heater 1401 were having problems and that they required constant attention and changing. The flame pattern was erratic and many employees believed that the heater regardless of its obvious deteriorating physical condition was being run very hard. The evidence also indicates that these concerns and attitudes were being brought to the attention of junior and middle management who appear at that time to show the same concerns. In an email dated 18 January 1998 from Gary O'Conner to Bob Stacey, Gary O'Connor stated:

> I must mention to you (so you will not be unaware) that heaters 1401 and 1402 are being used in a deplorable condition. While heater 1401 shell has deteriorated to a state where we are using lots of metal tape to patch the holes in it, my main concern is the internal condition of heater 1402. The bottom tubes have become almost completely covered in places with the insulation that once was on the walls, thus adding unwanted thermal stress to these tubes. I am very concerned about the safety of the units and the impact it has on everyone in them. Please e-mail me with an update on what and when we plan to do something about this.
> Ron, maybe out next "what if" should pertain to a tube rupture in heater 1402.
>
> Regards,
> Gary

On 19 January 1998, Bob Stacey replied "Thanks for the e-mail Gary, hope we survive until May 98". Both Gary O'Connor and Bob Stacey made a valiant effort at the inquiry to distance themselves from these comments and to reduce the clear meaning of the words in this e-mail. However, when the whole of the evidence is considered (including the safety concerns which I will address later) it is clear that heater 1401 in the spring of 1998 was an accident waiting to happen. It was "hoped" that all that an accident would not occur. In the words of another employee who was working at NARL at the time "It was not a matter of will it rupture again but when would it rupture again".

A considerable amount of evidence was presented at the inquiry both by the ground level employees, junior, middle and senior management as to the staff relationships that existed at NARL pre March 1998 (and after the incident). It is clear that a wide gulf existed between the ground level unionized employees and management before March 1998. Ground level employees in particular maintenance, safety and operation employees almost without exception testified that they felt out of the loop when it came to planning and changes to operating and working procedures. This is nowhere more apparent than in safety issues. For the purpose of discussion I include in safety: safety "culture" in that work place, training of employees, fire and medical procedures and emergency equipment, work permits and hazard identification. When NARL took over the Come-By-Chance refinery in 1994 the safety concerns of the staff were a major concern. NPL had operated the refinery for several years in a safety environment that was described as "dangerous" and hazardous. Equipment breakdowns, failures and fires were common place and safety appeared to be a low priority in the operation of the refinery. On November 25, 1987 NPL in cooperation with the United Steel Workers Union implemented a revised safety, health and environmental manual at the refinery. A similar manual had been in place since operations commenced at the refinery in the 1970's and the 1987 edition was inherited by NARL in 1994.

John Taylor was hired as fire and safety superintendent at NARL in 1995. He described the refinery in 1995 as being behind the times in fire and safety matters. The fire and safety equipment was "not realistic for our situation". He described starting his job at ground zero. He described some of the problems that existed in 1995.

1. Personal safety clothing, hoses and foam.
2. The SHE committee appeared to be us (workers) versus them (management). There was little or no trust between the two groups.
3. Unreliable UHF radios.
4. There were 350 safework orders before the SHE committee in 1995 and over 100 hazard operations files were filed on the heaters alone.
5. No written safety operating procedure was in place.
6. Fire crew numbers and training were below requirements.
7. No safety orientation was held for workers new at the refinery.
8. Fire and safety personnel had no involvement in risk and hazard identification.
9. Fire and safety personnel had no impact on planning at the refinery.
10. Fire and safety equipment was not up to the best industry practices and not up to date.
11. There was no systematic approach to fire and safety at the refinery.

When NARL took over the Come-By-Chance refinery in the fall of 1994 “all” equipment was checked and inspected and the number of programs and procedures were put under review. Some of these were “refinery standards, manual, plant safety manual and safety audits.

In the SHE committee minutes of November 24, 1994, attended by senior refinery management, the following was stated:

1. There should be a system where work orders are reported to the committed i.e. how many ongoing progress etc. Charlie Hamilton will issue safety work order procedure. Complete.
2. Safety audits need to be done before work is started and not after work has begun. The normal procedure is to do audit, make recommendations, and recheck a couple of days later to ensure that the recommended work is done. A procedure for this needs to be issued. Complete.
3. Work permit forms need to be revised. In preparation.

John Taylor was hired to organize the fire and safety department, the training and to determine safety and equipment requirements. He described senior management as accepting and willing to improve the situation and to expand fire and safety at the refinery. Between 1995 and the incident in 1998 NARL expended two and a half million dollars on fire and safety and equipment at the refinery. Involved in this expenditure were amongst other items:

1. New VHF radio system installed in January 1998.
2. Adoption of NAPA 1001 safety procedure (including auditing) which was being implement by March 1998.
3. A new draft SHE manual was completed by the 10th of March 1998 but it was not finalized by the incident in 1998.
4. Substantial increase in fire crew on each shift.
5. Fire crew was sent to Foxtrap for advanced training.
6. The health and safety complaint form was introduced in 1997.

7. The size of the fire and safety department, including training was increased from three to six and a formerly organized training program was put in place.

8. The management of change policy was introduced.

9. The management of process hazards was introduced.

10. An emergency response manual was proposed by 1997.

John Taylor testified that NARL was fixing the 1995 situation slowly. He described NARL as being six out of ten by 1998 and that everything was coming together. He described safe work orders as being a paper system before March 1998 and that at some time it would eventually get to the safety department. A slow improvement in this situation can be seen from the SHE minutes during the time frame 1994 to 1998. In July 1995 the executive committee of the SHE committee was in the process of putting together a top ten "hit list" for safety work orders and the top five environmental work orders. Very few of the 350 that had been outstanding in 1995 were closed by that time. In May 1996 the minutes of the SHE committee state "safety work orders were moving very slowly". On June 3, 1996 reference was made in the minutes to "some problems being experience during a fire on the day shift that day - the problem related to hit counts identifying marshaling areas and too many people in the location of the fire." A review of some of the incidents at the refinery that occurred in the year 1996 indicates that fires in and around heaters and tube problems did occur at that time.

96-11 Small fire in H1402, East End.

96-53	Fire occurred the SW burners of H1301.
96-121	Tubes ruptured in H1901.
96-196	Burner on H1102 coked (small fire)
96-212	Tube failure on heater 1401.

The committee was still concerned about the lack of feedback about investigations in February 1997. Finally in March 1997 the refinery made "someone", Rick Foulstone, responsible for reporting and ensuring that proper follow-ups were performed, this was after the February 1997 meeting where is was said "that some investigations are now being performed". Rick Foulstone was hired to follow-up on incident, accidents etc. and was being trained for investigations. By March 20th, 1997 he had an emergency procedure drawn up concerning control of emergency situations in the units as part of the emergency response manual. Several witnesses before the inquiry testified that safety and a safe work environment were not important prior to August 1994 and that the work environment was dangerous at that time when the refinery was being operated by Newfoundland Refining. There was an improvement from 1994 and the improvement was continuing. However, as late as January 20th, 1998 the minutes of the SHE committee meeting state "safety work orders not getting proper attention." One employee testified "they didn't care about nothing .... there were inadequacies in safety". Another employee testified at the inquiry that the SHE committee was not heard from very much before 1998. He was aware of the existence of the committee but did not know who his representative was on the committee and did not know if the committee was involved in the heaters.

Another employee testified that the safety department had no input in the job planning, risk and hazard identification and that the planners, purchase managers and engineers did the initial planning and equipment purchase and they, the planners and engineersm, ensured that the work or equipment complied with the risk and safety procedures in place at that particular time.

Several employees, including supervisors, testified at the inquiry that they took no safety courses before 1998. Another supervisor testified that he was stepped up to supervisor on a shutdown with no additional safety training only on-the-job training. Another described no set policy or procedure in place to obtain a safe work permit and no set procedure or policy in place for hot work on live heaters before 1998. Several employees recall being made aware the existence of a safety manual, but they were not given it to read and were not instructed to read it. Another employee recalled having no knowledge of any safety or emergency procedure to deal with a March 25, 1998 type incident. One supervisor testified that "as regards safety, a lot of times you have to make your own plan and work scope".

It was a common thread throughout the evidence of the non-management employees of NARL that safety in 1994 was "not considered important" and was subservient to "making money". The evidence also shows that NARL recognized the deficiencies in safety, equipment and safety procedures in 1994 and set about to correct the problem. As is clear in the safety committee minutes. On the 21st September 1995 those minutes state:

> “Dennis (Huckaby) reiterated that the committee’s mandate is to set the tone for safety in the refinery emphasizing that this is not just another committee. Questions should be of the type ‘What are the worker’s concerns? What needs to be addressed?’ Dennis voiced the opinion of management that safety awareness programs are very important to everybody at the refinery and that the role of the committee is to endorse all safety procedures that are instituted. In addition, management is committed to getting in compliance with API 750 - our refinery’s future ... it was noted that three people on the executive committee prioritized the safety work orders resulting in about 80 removed all together or taken care of out of about 1400. The work orders are backlogged ... they are being worked on but these things take time.”

In the SHE committee minutes of March 29, 1996 it is stated:

> Dennis (Huckaby) reviewed refinery economics/budget with committee emphasizing the importance of prioritizing safety issues, of finding economical/inventive solutions to minor concerns.”

It is clear therefore, that senior management at NARL recognize the importance of fire and safety, especially as this issue was an important factor in the general insurability of the refinery. Positive steps were being taken to increase the size of the safety department, safety equipment and improve safety procedures from 1994 to March 1998. However, when one reviews all the documentation it appears that economic priority to this aspect of the refinery was lower than that given to the process and production side. Further, employees at the lower level and at the lower supervisory level were not properly informed of the ongoing policy and procedure formulation and as a result saw few changes at their level of work.

Jamie Beach was hired in February 1998 as safety superintendent at the refinery. He entered upon this job with a clear understanding that safety was becoming an important part of the operations of the refinery and that the refinery was implementing the necessary American Petroleum Institute (API) standards. It is unfortunate that the incident of March 1998 occurred before he could implement further improvements in the safety of the systems and procedures initially commenced in 1994. Management, at the same time, was also increasing the size of the QC department from 2 in 1994 to 5 in January 1998. This indicates a recognition of the importance of this department. That department was beginning to develop plans and procedures that were not completed by 1998 but, which in most cases, were completely implemented after March 1998. Curtis Williams testified that efforts were being made from 1995 to 1997 to implement imposed policies and procedures, however, due to lack of organization, they were not completed by March 1998. It is interesting to note that John Taylor described the March 1998 incident as "causing turmoil" at the refinery as regards safety. After that incident the whole attitude of the refinery changed to a "safety conscious" workplace.

Heater 1401 continued operating operating from the shutdown in September 1997 until the incident on March 25, 1998. (Other than power failures.) During that time it ran better than it ever did before (from one operator). On two occasions in October 1997 and one on March 11, 1998, it was operated over its design fired duty, however, for the remainder of that time it was run within design. The pass outlet temperatures for the bottom runs (one to four) climbed over 700°F from November 1997 to March 1998. UOP specifications designate 695°F as the correct outlet temperature. The only "significant" operational facts that occurred during this period were:

1. Skin temperature. The design skin temperature that is the maximum tube wall temperature was set by UOP at 771°F. After the steam spall at the shutdown in December 1997 the temperatures on the north wall tubes began to increase and they were run substantially over the 771°F to a temperature of up to 950° just before the March 25, 1998 incident.
2. Viscosity of the RFO was low until April 1997. It ranged from 10,000-47,000 CS at 100°C due to the refining of heavier type crude. It decreased to 3,000-5,000 CS by mid-December 1997. However, from mid-December 1997 to March 1998 it increased from 15,000 to 43,000 CS. The recommended viscosity in heater 1401 at the burner tips per UOP is 20 CS. The operational conditions existing in heater 1401 during this period of time results in a viscosity of 100 CS. This results in inadequate combustion and can affect peak heat flux. This can also cause incomplete combustion in the burner guns, coking, gun replacement and can cause erratic flame patterns which can result in flame impingement on the tubes. It also results in the necessity of increased temperature to heat the naphtha feed to the necessary outlet temperature. These problems were compounded by low inlet temperatures and a mixed flow caused by the non-symmetrical input pipe line-up that existed at the time.

The heavy crude being refined for several months before March 1998 not only caused viscosity problems, it was also high in sulphur. Increased sulphur content escalates internal corrosion of the tubes. This is further compounded by the installation of the sulphur guard in September 1997. This caused less clean feed to enter heater 1401 and at the same time caused more product (from the CDU) with potential or fouling nature to be added.

I will now review in some detail the events of March 25, 1998. I believe this is best done by reference to activities of Jerome Kieley and James Mercer on that fateful day.

JEROME KIELEY

Jerome Kieley was a full-time employee of NARL and was a senior operator on the day shift in units 14, 15 and 25 on March 25, 1998. The operators on duty that day were Rick Connors (on the unit since December 1997) and Greg Maidment, a trainee master technician. A safe work permit was signed by Rick Connors at approximately 7 a.m. and a gas test was performed at that time by Greg Maidment, Jerome Kieley was present when this was conducted and the permit was signed by the supervisor Gord Kenny. On that day Paul Butt relieved Jerome Kieley when he went for his lunch break. On March 25, 1998 pre-shutdown work which had commenced on March 24, 1998 was continuing on heater 1401. Jerome Kieley does not appear to have been involved in investigating the "bang" (see later in report) heard around H1401 in the afternoon of March 25, 1998. He took his third break of the day around 3 p.m. and returned to work in the units at approximately 4 p.m. He remained in the warm-up shelter with Greg Maidment and Rick Connors for ten minutes. During that time Greg Maidment informed Jerome Kieley that he and Rick Connors had changed two burners on heater 1401 (at 15:28 and 16:00). Jerome Kieley and Greg Maidment left the warm-up shack and walked through rack three to the west of heater 1401. Jerome Kieley noticed the middle burner at 1401 flashing in and out. He and Greg Maidment walked up onto the observation deck at the west end of 1401 and adjusted the air doors (louvres which are vents around the burner to control the amount of air). After the adjustments were made the flashing in the middle burner continued. Kieley and Maidment then decided to change the "gun" again (it had been changed twice before that afternoon). Maidment obtained a gun from the gun shack and put another tip on that gun. The new gun was then installed. The flame appeared to stabilize for a few minutes but then began to flash again. Jerome Kieley walked to the east end of the heater to check the flame and Greg Maidment remained on the observation deck/landing on the west end (approximately 7-8 feet off the ground and measuring 4 x 8 feet approximately and which is surrounded by a hand rail). Greg Maidment again adjusted the air doors. Kieley called Maidment on his radio and said "Everything looks good". Jerome Kieley then walked back to the west end of the heater. The middle burner again began to flash in and out. Rick Connors then came by and Jerome Kieley, Greg Maidment and Rick Connors were all on the observation landing looking into the heater. There was not much room for the three of them on that landing. Jerome Kieley instructed Greg Maidment to go and take a water sample to the control room and to bring up the daily log (prepared about four p.m.). At that time Jerome Kieley was unsure what else to do with problems going on in 1401 and decided to leave it alone for a while. Jerome Kieley, Rick Connors and Greg Maidment were at this point standing in front of the heater when this decision was made. Greg Maidment then left as per his instructions. As Greg Maidment left to go towards the lab (next to the control room) he heard Paul Burton call on the radio to check the heaters because the transfer temperature had risen 4°. Rick Connors remembered Paul Burton saying the skin temperature had gone up 30°. Paul Burton, who was in the control room, gave evidence that the outlet temperature was up 3 or 4° and the skin temperature 20° (from 700 - 720°F) and rising slowly. (The outlet temperature is an average of the four passes.) Paul Burton then called the operators on the radio and Jerome Kieley answered. Paul Burton asked Jerome Kieley to have a look at the heater. In the control room Paul Burton had just returned to replace Cliff Strowbridge. Cliff Strowbridge informed Paul Burton on the changeover that two burners had been changed in 1401 and that the heater was taking a bit of a swing. He, Paul Burton, was checking his readings and noticed that the outlet temperature was not steady at 630°, it began to rise to 634 and 635 and was continuing to rise. The skin temperature was at 720, however, it too began to climb to 730. The increase in the skin temperature caused Paul Burton to be concerned and raised a red flag in his mind as he knew that usually only one thermocouple was operating on H1401. He initially thought that a bad burner flame was impinging on the skin temperature gauge and hence the increased reading. This had occurred many times before and was usually caused by a bad or dirty burner coking off or an increase in flame size. The pressure readings at this point were normal and not moving. It should be noted that the temperature that appeared on the control room panels are an average over a two minute time period.

Jerome Kieley and Rick Conners went up the ladder to the observation landing at the west end of heater 1401 to again adjust the air louvres on the burner to see if it would make any difference. Jerome Kieley believed that if the heater received more air it may cool down the tubes. Rick Connors was on the observation deck at the west end of the heater standing one or two feet from Jerome Kieley to his left, with the ladder directly behind him. Approximately one minute after Paul Burton called on the radio and requested them to check the heater Jerome Kieley leaned over to almost knee level to adjust the louvre doors on the middle heater and in the words of Rick Connors “she blew”. Jerome Kieley was completely engulfed in flames and disappeared from view. The leg of Rick Connors overalls and the outside lining of his web pants were blown off and his clothes caught fire. His face and wrist were burned. Rick Connors is not sure if he got down the ladder himself or he was blown down, however, when he hit the ground he started running and trying to remove his burning coat. Rick Connors ran down through rack three towards the permit shack (to the north). As he ran from the scene he observed Jerome Kieley half-way through the racks more or less crawling west.

JAMES MERCER

James Mercer was a welder on the maintenance staff and a temporary employee at NARL on March 25th, 1998. He had been instructed to carry out air gouging on the panels of heater 1401. He was instructed to cut the seal between the panels and to cut off every second bolt that held the panels together. By doing this work on the live heater before the actual shutdown, it would shorten the period of shutdown by several days and therefore would save considerable money to the refinery. He commenced work on the heater on March 24. He began at ground level on the vertical south side of the heater and worked his way up the radiant section towards the hip. NARL had supplied the welders with a welder's shield, a leather hip length jacket to protect them against sparks and flying metal and a hard hat. As a temporary employee, Mr. Mercer was responsible to supply his own clothing, cotton coveralls on his legs and steel toed boots. In March 1998, Nomex clothing was only available to full and some part-time employees and those who worked on the units, not temporary employees doing welding. Marvin Wells was also carrying out the same type of work on heater 1401 on March 24th and 25th, 1998. Marvin Wells gave evidence that he was very apprehensive and uncomfortable about working on heater 1401. He personally felt that air gouging on a live heater was dangerous and that "sparks" could travel up to a hundred feet and were difficult to control in a confined area. He stated that the area in which he was working that day was not a controlled hot work environment. He was especially concerned due to the condition of the panels of 1401. He described the panels as being so deteriorated that he could look into the furnace through the holes, even though some had been taped. He described the area as being extremely explosive and dangerous. He testified that "we" expressed our concern to their superior, Gordon Kenny, but not forcefully. Gordon Kenny tried to ease their minds. However, as they were only temporary employees and could easily be replaced, they felt that they had to do the work even though they were uncomfortable with it. (James Mercer and Marvin Wells were both temporary employees). Marvin Wells was very forthright in his evidence and in his opinion doing the job was "crazy". He describes actively looking for escape routes if an emergency occurred. However, he did commence and continue with the work. Just after lunch, sometime after 1:30 when Marvin Wells was not gouging, he heard a "sharp pop" or "bang", which was like a loud clap. He was not sure if it was coming from inside or outside of the furnace but it sounded like something out of the ordinary. He noted that he would not have been able to hear the noise had he been gouging due to the noise of the gouging and the earplugs he wore. Upon hearing the noise he stopped and went over to Jim Mercer, asking Jim Mercer if he had heard "the bang". James Mercer replied he had not. At that time, James Mercer was about ten feet above the electrical panel on the vertical south face of heater 1401 between the pipes and the heater, in a very cramped space, air gouging. Marvin Wells asked Jim Mercer if he had cut off a bolt as he had initially thought the noise may have been a falling bolt hitting an angle iron or the galvanized roof panel of the electrical panel located below where Jim Mercer was working. As Marvin Wells and Jim Mercer cut the bolts holding the panels together, the panels sometimes expanded and made a popping noise. 9Cecil Simmonds, a supervisor, said this is a common occurrence in cutting bolts.) James Mercer replied he had cut off a bolt a few seconds before, although at that time he was gouging the seams and not the bolts. James Mercer and Marvin Wells left their gear and asked Perry Butt, their "spark watch", if he had heard the "bang" and he replied that he had. Perry Butt stated that the noise sounded "awful queer". They collectively decided to get the "noise" checked out. Marvin Wells did not think it was a bolt because Jim Mercer was gouging seams not bolts and the electrical panel below him was covered by a blanket and hence it would have muffled the sound and the noise and would therefore, probably not have been heard by Perry Butt. Marvin Wells walked to the shutdown trailer, located parallel to heater 1401 but slightly to the north. He spoke to Gord Kenny asking him if anything had gone wrong with the heater. Marvin Wells and Gordon Kenny walked to the operation shack and asked the operators to check out the heater. At about three o'clock or shortly thereafter, Greg Maidment and Paul Burton (who had relieved Jerome Kieley while he was on his break), a senior operator, were the operators on unit 14. Gordon Kenny came to the door of the operations shack and informed them that someone had heard a "pop" or "strange noise" around heater 1401 and could they have a look at it. Paul Burton called the control room and talked to Cliff Strowbridge, a control technician. Paul Burton asked Cliff Strowbridge if everything was okay with 1401. Paul Burton testified that given the history of 1401 and its deplorable external condition, he wanted to ensure all was normal before he went near it to check it out. Cliff Strowbridge informed Paul Burton that everything appeared all right in the control room. Paul

Burton picked up a gas tester and walked completely around the heater doing a visual inspection and gas test as he walked. Paul Burton testified that if there had been an obvious gas leak, it would have been very apparent and the gas tester would pick up any gas coming from the pumps or the rack. However, he added that a gas test would be of no help in determining if there was a tube leak as a gas tester tests for oxygen and H_2S and combustibles, none of which are contained under pressure in the naphtha in the tubes. He testified he then got up on the scaffolding and combed the area of the heater. He told the inquiry that Jim Mercer had joked "I guess if that heater blows up the gas tester wouldn't mean very much". Paul Burton testified that he had a conversation with Jim Mercer who was standing on the ground south of the heater 1401 between heater 1401 and 1501. Jim Mercer informed Paul Burton that he did not hear anything but the noise might have been a bolt that fell, a normal occurrence. Jim Mercer did not express any concern and appeared to be quite jovial. Paul Burton then looked at the burners of 1401. He looked into the east end of the heater and observed that the middle burner on the west end was veering to the south side. The flame from the burner was erratic and not steady. Paul Burton believed that the cause was a dirty burner gun. He saw no evidence of any leaking tube. He testified that even though he had never seen the effect of a tube leak in a live heater he was sure he would have heard, smelt and seen such a leak and that it would have been noticed in the gauges in the control room (450 psig pressure). Veering flames in a heater have to be attended to. Paul Burton contacted Chris Strowbridge in the control room and informed him that they were going to change a gun. Greg Maidment obtained a gun from the burner shack and Paul Burton and Greg Maidment took a minute or two to install the new gun. The burner appeared to perform better than before but was not perfect. It was not veering as much to the south as before, however, Paul Burton decided to change the gun again. Greg Maidment again obtained a new gun and the burner was changed again. The flame pattern was still not perfect, it was still unsteady and Paul Burton speculated that it may have been a problem with the tiles around the burner. Jerome Kieley then called Paul Burton and informed him that he was on his was back from break. It was now close to 4 p.m. Paul Burton informed Jerome Kieley when he returned of what they had done, about the "pop" sound, their checking the heater, the gas test and changing the burners and that the last one that they had installed was still not great and that he thought that Jerome Kieley should have a look at it when he went back to the unit (this discussion took place in the Isomax hut). Paul Burton ate his lunch quickly and went to the control room to relieve Chris Strowbridge. Marvin Wells and Perry Butt reluctantly went back to work on and near 1401 respectively. Jim Mercer returned to the south vertical side of 1401. Marvin Wells was still very apprehensive and took advantage of an excuse to stop work on the heater in order to obtain a piece of wood to place on the hip section of the heater to enable him to keep gouging. Jim Mercer was located approximately 12 - 14 feet up the south vertical wall of 1401, his legs over the piping and still in a very confined space. Perry Butt, the spark watch, was located on the east end of heater 1401. At approximately 4:50 he picked up a piece of plastic off the ground and was reaching to put it into a garbage can near the welding machine located at the east end of heater 1401. He turned around and in his words "she blew up". He was blown end over end by the concussion. He picked himself up, heard roaring and observed a massive ball of flame rising from heater 1401 and felt heat from the flame. He could not stand the heat and ran behind some barrels nearby. No fire alarm went off. He knew Jim Mercer was on the heater and waited hoping he would come out of the flames. In a few seconds he observed Jim Mercer walking out of a black ball of fire about 40-50 feet from him between heater 1401 and 1501. Jim Mercer stood for a moment looking around. Perry Butt described Jim Mercer as "burnt pretty bad". Jim Mercer then walked toward a substation to the north of heater 1401. Perry Butt then ran up the hill to the east of 1401 to a lunch room. The fire whistle then blew. Perry Butt has not worked at the refinery since March 1998 and has required psychological counselling to deal with the trauma of the experience he suffered in March 1998. He was informed by NARL's doctor that his services were no longer required at the refinery.

After heater 1401 caught fire, in the words of one employee, "all hell broke loose". Reaction was immediate but was described as a panic situation. One employee testified that everything was so confusing and so loud, another said he couldn't function. At the time heater 1401 "blew", an usually large number of additional employees were available at the refinery as a training course was being held that day.

Jamie Beach was in the fire hall talking to Ray Guy of Occupational Health and Safety Province of Newfoundland and Labrador and Jerome O'Keefe, the chair of the SHE committee, when he heard a loud "bang" followed immediately by the fire whistle. He left the meeting, got aboard the fire hall van with Rick Foulstone, drove toward the NHT unit and parked on the north side of rack three just west of the substation. He began to walk towards Gerard Lynch who was just inside the west end of rack three. Within three or four minutes of hearing the fire whistle he met a person, Jerome Kieley, walking out of the rack towards him. This appears to contradict the evidence of Gary O'Connor who said he saw Jerome Kieley crawling out of the rack. Nevertheless, Mr. Beach described Jerome Kieley as obviously severely burned, his jacket was smouldering, and Gerard Lynch and Jamie Beach stopped and helped him remove his outer garments. Jerome Kieley was saying that he was very hot and his clothing was still burning. Jamie Beach instructed Rick Foulstone to take Jerome Kieley to the fire hall using the fire hall van parked nearby. Jerome Kieley walked to the van and was on his way to the fire hall within three or four minutes of Jamie Beach arriving at the scene.

Rick Connors was a trainee operator in March 1998. He had worked on maintenance for 15 years and had been in the NHT unit since December 1997. He heard one of the boys over the radio saying that there was a problem with one of the burners in heater 1401. He and Jerome Kieley went to the heater. Jerome Kieley went to the west end and Rick Connors to the east end. Rick Connors described what he saw in the heater on the radio, he observed the middle two burners on the west end veering to the south, that is away from the area of tube 9. Jerome Kieley then made adjustments at the west end but these adjustments were unsuccessful in that the flame was still veering to the south. Jerome Kieley and

Rick Connors then went to the burner gun shack behind heater 1502 and looked at the gun recently changed out of 1401. It appeared to be alright so they decided to leave the burners alone for awhile and only change the gun again if necessary. There had been four burner gun changes on heater 1401 on March 25, 1998. It takes about 30 seconds to a minute to change or adjust a burner and these adjustments will show in the control room by as a much as a 20° temperature change. If a new gun is installed and works well, the temperature change should only be from 5-10°F. When the new gun is deployed the temperature drops, overshoots and backs up again to the set point (625°F as set by process engineering). Evidence of the burner gun changes can be seen in the operation records of the control room on March 25, 1998. Cliff Strowbridge, an operator, testified the changing a burner gun, three or four times on a shift as "getting out of normal" and it should be investigated.

After Rick Connors ran from the scene he met Bruce Wiseman at the end of rack three and saw Gary O'Connor on the radio. He then observed Jerome Kieley more or less crawling out of the rack after the explosion. This is the rack behind heater 1401 rack three. He also observed Jim Mercer coming around from the east end of heater 1401 towards the permit shack, he appeared to be badly burned. He observed Bruce Wismeman get a gel blanket and cover Jim Mercer's legs. Rick Connors testified that Jerome Kieley was put in a van and moved to the fire hall within three or four minutes of the incident. He described the response to the event as immediate.

Cliff Pollett was a lab technician and had worked at the refinery since 1988. He had been a member of the fire crew - emergency response team since 1990. He was one of five or six persons so designated on March 25, 1998. He heard a “rumble”, the fire alarm went off and the fire phone rang in the lab. He took a minute or two to put on his fire gear (burner gear). Normally a vehicle was located by the lab to allow quick access to the area of any fire, however, it was not present that day and he personally ran approximately 300 feet in full bunker gear to the location of the fire. This took him about three minutes. By the time he arrived at the scene the fire trucks had already arrived. He saw a person (James Mercer) sitting on the ground being assisted by an operator who had wrapped a fire blanket around Mr. Mercer’s legs. Mr. Mercer was conscious and aware of what happened (at a later time Mr. Mercer informed another employee that he climbed down to the ground where he was gouging immediately after the heater blew) but he was not aware of the extent of his injuries. Cliff Pollett described James Mercer’s injuries as very severe and obviously life threatening. The only thing he could do was to talk to James Mercer and to try and calm him down as Mr. Mercer was in a fair bit of pain and frightened. This is all Mr. Pollett could do at this point as he did not have a trauma kit with which to treat Mr. Mercer. Mr. Pollett attempted to get an ambulance and was told it was on the way, as a result Mr. Pollett became agitated. Finally a pick-up arrived and James Mercer got up into the front seat and was driven to the fire hall. Mr. Pollett testified that Mr. Mercer was on the ground for approximately 20 minutes waiting for removal from the scene. Mr. Pollett also confirmed that he never did get a trauma kit while waiting with Jim Mercer. He also described having no radio to communicate in order to obtain a trauma kit or ambulance. After the incident, handheld radios were provided to the emergency response team, however, it was activated by push button and hence a first aider could only use one hand to help an injured person at the scene when he was operating the radio. The new radios did not have a headset free headphone to allow him to work with both hands on any injured person at the scene of an incident.

When he arrived on the scene, Jamie Beach was informed by Gerard Lynch that the control room was in the process of shutting down the unit, but at that point it had not been shut down completely. The fire hall trucks attempted to hook up to the hydrants, however, there was some delay as the lugs on the hydrants were frozen or stuck. The overhead monitors were activated although their operation was also delayed due to stiff valves or lugs or bolts. Once they were operational, the water from the hydrants and the overhead monitors was used to stop flamed impingement on nearby equipment and thereby isolated the fire to heater 1401. However, the flames were so intense that some flame impingement was occurring on nearby exchangers so Jamie Beach ordered that handheld hoses be used to provide further protection to the nearby equipment of rack three. The compressor CH1402 located in rack three behind the west end of 1401 was manually turned off by Bruce Wiseman about ten minutes after the fire started, it had already been tripped by the control room to stop the flow of hydrogen. The snuffing steam valve behind heater 1505 was also turned on and snuffing commenced putting steam into the furnace and the flames went out. The all clear was sounded at 6 p.m.

Jerome Kieley, James Mercer and Rick Connors were transported to the James Cross Hospital at Clarenville. Jerome Kieley and Jim Mercer were later air lifted to St. John's.

James Mercer died of acute renal failure due to 50% body burns and heat inhalation at 8:14 a.m. on March 28, 1998. Jerome Kieley died of sepsis due to full thickness burns to his body at 9:38 p.m. on April 3, 1998.

As a consequence of the accident on March 25, 1998 several investigations were carried out.

1. Office of the Fire Commissioner who retained A.D. Tupper and associates Ltd. Consulting Engineers to investigate the cause, origin, extent and circumstances of the incident. Mr. A.D. Tupper, P. Eng., then retained Innova Corp to perform metallogical testing.
2. Occupational Health and Safety Boiler Pressure Vessel Branch of the Provincial Government of Newfoundland and Labrador.
3. The Department of Municipal and Provincial Affairs, Government of Newfoundland and Labrador retained Brown and Root Limited of Aberdeen, Scotland to conduct an audit of the operations of NARL. This included a review of the physical refinery at Come-By-Chance, an assessment of the management techniques and personnel and an examination of the inspection and audit process of the various government departments.

4. NARL, the operator of the refinery, carried out an internal investigation and retained Shell International Oil Products of Amsterdam, Holland to investigate the cause of the tube rupture on the 25th of March 1998 and to recommend improvements to avoid reoccurrence.

5. The Royal Canadian Mounted Police.

6. NARL set up a committee to prepare a report on heater 1401.

A review of the results of these investigations in the context of all the evidence tendered at the inquiry points to the following factors as to contributing to the failure of tube 9 in heater 1401 on March 25, 1998 and thereby also contributing to the deaths of Jerome Kieley and James Mercer whose injuries were caused by that failure. These points are numbered not according to their order of importance or significance.

1. Internal corrosion
2. External corrosion
3. Possible pipe stress
4. Flame impingement
5. Refinery fuel oil
6. Burner overfiring
7. Skin tube temperature
8. Inadequate tube wall measurement procedures
9. Tube life expectancy
10. Tube metal selection

11. Perforations in heater casing

12. Excess air

13. Upline equipment fouling

14. The type of heavy crude being refined

In addition to the above physical factors other factors contributed to causing the incident.

15. Safety training at NARL

16. Safety and emergency equipment at NARL

17. Employee and supervisor/management training at NARL

18. Government inspection of refinery operations

19. Training of contractor employees working on site

20. Safety planning not included in long term and project planning at refinery.

I will address each of the physical and other factors set out above that contributed to the incident but first the issue of whether there was an explosion at all and the ignition source for the event has to be addressed.

In order to determine the cause of a fire event or explosion it is necessary to establish the initial fuel and ignition source. Evidence at the inquiry described an immense fireball external to the heater which turned into pressurized balls of fire coming out of the heater stack. It appears, therefore, that almost immediately after the ignition of the naphtha feed, a fire occurred both inside and outside of the heater. It is clear that the fuel for H1401 "explosion event" was NHT processed fluid which was released from the unplanned rupture of outlet process tube no. 9

in the lower radiation pass on the north wall of heater 1401. The rupture occurred immediately opposite the top burner and the open end of the failed pipe pointed almost directly at one of the burner observation ports on the west end of the heater. (Where Jerome Kieley and Rick Connors had been standing.) The naphtha material inside the failed tube consisted of pressurized naphtha and hydrogen at a prerelease temperature of about 635°F and a pressure of 560 psig. Although such a mixture is exceedingly flammable when mixed with an appropriate amount of air, that material must be within the exposable flammable limits in the air if it is to burn.

A. Tupper was of the opinion that when the tube ruptured neither fire nor air explosion occurred inside the heater even though six burners were probably operating immediately prior to the rupture. He concluded that this probably meant:

1. The fuel mixture within the heater box was too rich, that is above the upper explosive limit and would thus not support combustion when it was first released;
2. The velocity which the released material passed across the face of the three westerly burners was such that it could have extinguished the burners like a candle being blown out particularly in view of the operators evidence that at least one burner had been going off and on before the event occurred.

Once the tube ruptured, however, the hot pressurized vapor traveled out into the firebox. The charge for the four passes was 179,800 pounds per hour of naphtha, plus 4,170 pounds per hour of hydrogen, for a total flow of 183,970 pounds per hour. Once the tube ruptured, the opening would produce a path of least resistance and the whole charge would tend to escape. This means that there would have been, from the ruptured tube, a flow in the order of 1.5 tonnes per minute. Using a conservative value of five minutes for the feed to be shutdown and the lines to depressurize, over 15,300 pounds of hot vapor would have escaped from the tube in that period of time.

The initial rupture caused a cloud of hot gases within the heater. The pressure of the cloud exceeded atmospheric pressure and the vapors would have tended to more vigorously from the pressurized chamber to the outside. Because the cloud of vapor was being feed for at least two minutes before the hydrogen compressor was turned off and the feed valve closed, the firebox would have remained under positive pressure during the interval and for some additional time until the coil depressurized. At that time, the mixture of hot naphtha vapor and hot hydrogen would have jetted out through all the available openings.

Once the vapor escaped from the confines of the heater, turbulence would have promoted mixture with the atmospheric air and portions of the hot exterior cloud would have moved into the explosive limits of the fuel. Once the air/fuel mixture was within the explosive limits, it could be ignited through the application of energy. Because the refinery tries to minimize potential ignition sources by using explosive proof electrical equipment, amongst other things, available ignition under these circumstances are relatively limited.

Evidence at the inquiry pointed to four potential ignition sources:

1. A welding machine producing an arc
2. A hot piece of gouged metal from the air gouging
3. Auto ignition
4. The heater burners.

Allison Tupper is of the opinion that one and/or two probably caused the ignition. Both Tupper and engineers from NARL testified that the auto ignition temperature of naphtha is unknown and it is only a possibility that the ignition could have come from such a source. NARL engineer Hallet, was of the opinion that the burners may have provided the ignition source.

What is known is that there was a spherical wave or pressure wave that caused the spark, Perry Butt, to be thrown to the ground, the shutdown trailer to shake on its foundation and a noise to be heard throughout the refinery. The physical damage to the heater suggest that the fire was mainly in the upper reaches of the heater and not at ground level. The physical damage to the heater was not as much as that which occurred in the 1998 explosion when the casing and structure were blown outward. Taking into account all the evidence which I have before me, I am unable to determine with certainty how the fuel/vapor mixture was ignited. However, I am satisfied that there was an explosion within the common meaning of explosion.

I would now briefly consider each of the other factors that I have set out above that contributed to the incident.

3. <u>Internal corrosion.</u>

Sulfidation and intergranular attack occurred on the inner diameter of tube 9 in heater 1401. The level of H_2S (hydrogen Sulfide) in the naphtha feed increased over the 1 - 1½ years before March 25, 1998 as the refinery purchased and processed a heavier crude which had a higher sulphur content. Chemical analysis of fouling deposits on the inside of the tube after the incident indicated iron sulphide, this is an indication of interior intergranular attack on the tube steel by an H_2S rich product stream. The internal corrosion due to sulfidation increased significantly over the 1-1½ years before the incident, coincident with the increased sulphur composition of the naphtha feed: more feed coming from the crude distilling unit and less from the hyrdrocracker. The corrosion attack on the interior of the tube can progress quickly and cause localized stresses. Measurements taken of the tube after the incident reveal that the effective tube wall thickness near the fracture face had been reduced to 0.067 inches, considerably less than the critical required thickness of 0.114 inches, the minimum wall thickness required to withstand the internal pressure in the tube. Management, Process Engineering and Quality Control at the refinery were all aware of the effect of the sulphur on tubes of 5Cr. In fact, from the evidence tendered at the inquiry is clear that 5Cr tubes are not suitable for use in areas of high sulphur content crude. As early as 1996, Curtis Williams recommended replacement of the 5Cr with a heavier steel, 9Cr, that recommendation was not followed by NARL management. In the meeting of December 5, 1996 in the detailed review of operating conditions item 3.5 said "corrosion losses may be contributing to creep failure. The use of 5Cr tube material may not be adequate for the current service". In this same meeting, sulfide corrosion was specifically addressed and it was noted that the deposits on the inner diameter had a significant insulating effect. It was also noted that previous UOP recommendations and current industry design practice is to use 9Cr as the material specifications for NHT charge heaters. It is clear therefore that the potential corrosion problem was known by senior management.

The tube measurements taken pre 1998 were sporadic, erratic and not site specific. The Innova report in referring to the ERA estimate estimated wall thickness in 1997 at 0.193 clearly points out that the erratic ultrasonic measurements indicated that the onsite equipment was out of calibration or that the measurements taken included thicknesses of scale on the inner surface of the tube or ignored the crevices present. Innova was of the opinion based on their analysis of tube 9 after the incident that intergranular corrosion had penetrated further into the wall of tube 9 creating a wall thickness that was less than 0.193, the recommended thickness for ERA testing in 1997. Innova does acknowledge that the serious effects of intergranular corrosion would be difficult to assess using either ultrasonic or caliper measuring devices, however, the corrosion was more severe than previously believed. Based on ERA estimates NARL believed that the tube had a considerable remaining life. However, as was already noted there were limitations in the ERA report. In addition management was aware of the previous tube failures in the heater, the recommendation of Curtis Williams to upgrade to 9Cr, the sulphur rich feed and erratic measurements, all of these should have caused the experienced senior process engineers to investigate the corrosion factor further before making further process decisions. In addition the flushing of the tubes of 1401 with acid in 1999 to clean out interior deposits in the tubes could have opened up the interior surface of the tubes to continued corrosion attack. This would have been exacerbated by the acid wash not being removed with soda ash, but with water only in direct contravention of UOP recommended procedures, and in spite of warnings from senior engineers to the Process Engineering Department at NARL.

2. <u>External Corrosion</u>

There was evidence of exterior pitting in tube 7 well before the March 1998 incident. That tube was the same age as tube 9. Innova observed surface oxidation of the outer surface of tube 9 as indicated by a dimpled and wrinkled appearance. Although not as severe as the interior corrosion attack it was a combination of the wall thinning both in the interior and the exterior of the tube that was the primary failure mechanism of the March 1998 tube failure. The internal and external attack on the tube caused an elastic yielding and tube failure. A. Tupper noted that the wall thickness measurements made from the inside of tube 9 show a thinner wall than those measurements taken from the outside. He opined that this is reflective of the exterior dimpling and demonstrates a problem with a normal exterior ultrasonic testing. Again this points to the lack of site specific regular tube measurements using accurate measuring devices. Again it is interesting to note that Curtis Williams, in 1996, recommended that a sample of the old tube be sent for analysis, however, only a new tube installed in 1993 was actually analyzed by ERA and was the basis of the ERA analysis. An analysis of an older tube in 1996 may not of itself prevented the March 25th, 1998 failure as the change in refinery crude caused sulfidation attack at an increased speed for a year to a year and a half before the incident. However, the analysis of an older tube in 1996 may have resulted in a detailed metallurgical analysis being available of a tube installed in the early 1970's, something that was not done by NARL until after the March 1998 tube failure. Such an analysis may have confirmed some of the known concerns in 1996.

3. <u>Possible Pipe Stress</u>

Tube 9 in heater 1401 was damaged in the 1988 explosion of heater 1401. It was bowed by that explosion and was physically straightened using an acceptable correcting procedure. Evidence of continued bowing appears on a consistent basis in the evidence tendered at the inquiry. On July 7, 1997 the heater group was made aware of this continuing situation and the operation log of December 10, 1997 noted bowing, yet no evidence that the members of the heater group, some being experienced engineers, took any action to remedy the situation. An inspection after the March 25, 1998 event revealed that the bottom north radiant coil had moved easily a distance of 12 ½ inches. Tube 10 had also shifted in 1996 when a pin had sheared. A. Tupper opined that the March 28, 1998 movement could have been in reaction to the discharge of the process fluid from the tube rupture or it could have been a result of unplanned internal stress in the piping. Tupper also pointed to the September 14, 1994 hydrostatic testing carried out on the tubes in heater 1401. The design test pressure was 1100 psig for 30 minutes. Heater 1401 was hydrostatically tested at 1300 psig (in the presence of BPV inspector). In the opinion of Tupper this increased pressure could possibly have aggravated stress accumulation, prompted stress related corrosion and other deleterious effects on the subject coil and as a consequence could have shortened the life of the tube. Evidence of stress to tubing operating in such a hostile environment as in heater 1401, in particular the bowing of the tube, should have been addressed immediately. Although stress need not of itself had caused the tube failure it may have contributed to the failure.

4. <u>Flame impingement</u>

All the tube failures on heater 1401 prior to March 25, 1998 were attributed to localized short or long term local overheating. Evidence of flame impingement was apparent on all previous failures. The flame impingement was especially prevalent when the burner configuration was triangular. The heat flux on tubes one to four inclusive was excessive probably due to irregular flame pattern. This caused higher than normal tube skin temperatures, accelerated oxydation and formation of speroidized carbides at the grain boundaries. Flame impingement continued due to problems with improper combustion (due to burner guns and the RFO fuel, CS factor and burner misalignment) right up to March 25, 1998. In fact the flame pattern on the afternoon of March 25, 1998 was being adjusted when the tube failure occurred. Innova found that the failed portion of tube 9 exhibited visual evidence of flame impingement, but that it had not affected the microstructural properties of the tube. However, creep and microcracks were present in the immediate area of the failure, which indicates localized overheating. Hence in addition to the internal and external corrosion the tubes were subjected to localized overheating in the location of the tube failure. NARL was made fully aware of the risk associated with flame impingement causing localized overheating. In fact it reconfigured the burners to reduce the likelihood of flame impingement. It also replaced several burners that were misaligned and erected a wind break to take account of wind gusts affecting the flame pattern. However, flame impingement was a continuing problem. On December 3, 1996 it was decided by senior NARL management that testing for first and second stage creep for tube life determination be made part of the normal quality controlled inspection shutdown schedule, however, this was only declared as a "long term" goal. It had not been put in place by March 25, 1998. It is fair to say that NARL believed that any tube failure in heater 1401 or other heaters would likely be a result of localized overheating as it had in past occurrences. ERA had opined in 1996 that if overheating was eliminated, creep failure would be prevented and the tubes would fail due to elastic yielding caused by wall thinning. ERA based this calculation on a wall thickness of 0.193 inches. Innova opined that "in retrospect this value may not have been a good assumption" and for reasons already set out the life remaining calculations of ERA were based on erratic measurements (reported to ERA by NARL) and questionable assumptions. Again NARL believed on the basis of the ERA report that the tubes had significant remaining life, however, we know now that this was not in fact the case. NARL knew of the problems that were readily apparent in heater 1401 and one operator gave evidence that "flame impingement was only logged if it was continuous". It is clear therefore that flame impingement occurred regularly and was addressed by the operators but for some reason was only logged if it was continuous. In light of the comments of ERA as to the importance of flame impingement on the tubes, this is a matter that should have been given more consideration by senior NARL management.

5. <u>Refinery fuel oil (RFO)</u>

NARL was aware that fuel tank T-641 which supplied the heater 1401 furnace with RFO was due to its design unable to increase its maximum allowable fuel temperature to that which was required. The temperature could also not be increased in exchanger 3501. Viscosity had increased for two periods in1997. In order to achieve a viscosity at the burners at 45 CS (NARL's goal) when burning heavier crude the temperature of the fuel oil would have to be increased from 195-210°C to 240°C. However, the fuel temperature exiting H3501 (upline of H1401) did not exceed

220°C, some 20° below that required. Proper viscosity of the burner tips is necessary in order to obtain good atomization and combustion of the RFO. For H1401 type burners, a viscosity of 20 CS is advised, not 45 CS. Hence NARL was using a higher than recommended viscosity at the burner tips. Further, the temperature at the burner tip dropped seven degrees, further compounding the problem. The result of all these factors is that a viscosity of over 100 CS occurred during periods in 1997-1998 when the refinery was processing heavy crudes. Such a low viscosity results in inadequate combustion. In addition it has an effect on the heat flux, as the flames are more luminous, causing radiated heat to increase, and as a result the tube wall temperature also increases. Further, NARL was using two types of burner guns in the burners, only one of which was recommended for use. NARL was aware of this situation for some time before March 25, 1998. No evidence was tendered that any plans were current in March 1998 to correct these problems even though they were aware of their potential ramifications.

6. <u>Burner overfiring</u>

The evidence tendered at the inquiry indicated that heater 1401 was being run "hard" up to March 1998. The radiant section of heater 1401 was run 14% over design in 1996 and again over design in 1997. The overfiring was partly a result of tramp air introduced into the heater through holes in the heater casing and partly because of the insulating effect of the an internal layer of scale. Due to fouling in the combined feed exchanger, full vaporization had not taken place before the naphtha feed entered heater 1401. This caused an imbalance of flow through the passes and further increased the load on the heater, for the incoming naphtha liquid needs to be vaporized, and such vaporization requires extra heat from heater 1401. This problem, amongst others, was identified in the meeting of December 3, 1996 but no priority was assigned to correct the problem even though reference is made to it as late as the fall of 1997.

7. Tube skin temperatures

The maximum tube wall/skin temperature for the radiant tubes is 771°F. This was set by Procon (Great Briton) and adopted by UOP. It is recognized that this figure includes a built in safety factor, however, it is also clear from the evidence that heater 1401 was consistently and over a long time operated or a skin temperature exceeding 771°F. ERA used a maximum testing temperature of 850°F and also calculated the remaining life of the tubes if higher temperatures were in fact used. It was noted in that report that local overheating, both short and persistent must be controlled in order to achieve a desired tube service life. Heater 1401 was not initially designed to use thermocouples to measure the tube wall temperatures. However, NARL began to install them in 1994 on the lower rows of tubes when two knife edge thermocouples were installed. Placing them in the lower rows was understandable as that was the location of maximum heat flux when the burner pattern was triangular. Four more Gayesco shielded design type thermocouples were designed in 1995, again on the lower tubes. Some of the thermocouples installed were not designed for heater 1401 and were "adapted" to fit the heater. The radiant heat from heat flux has a great affect on tube skin temperatures. The design maximum flux density was set at 18,000 btu/ft^2/hour. In a detailed combustion review of heater 1401 conducted on December 17, 1996 (Willis) the maximum peak flux rate at the nearest point to the flames (tube rows 1 to 4) was 22,815 btu/ft^2/hour, which exceeded the design maximum. This was recognized by NARL when it reconfigured the burners from triangular to vertical in 1997. In the same analysis the total average flux rate for tube 9 in the triangular burner configuration was estimated and 6,815 btu/ft^2/hour. This was estimated to increase to 13,684 btu/ft^2/hour under a vertical arrangement "if" flames were in the required patten. Erratic flame patterns cause increased heat flux to the tubes. The realignment of the burners placed tube 9 in an area of increased tube flux and therefore would have increased the tube skin/wall temperature. No further analysis of the heat flux in heater 1401 was conducted by NARL before the March 1998 incident. In the Shell report it is noted that the pattern of previous tube failures in heater 1401 coincided with the location of the higher heat flux which was located near the burners. This information was know to NARL in 1996. Being that tube skin temperatures are critical it is very surprising that on March 28, 1998 only two thermocouples were actually operating and these were on the lower level tubes (tube 2, north and south wall). In effect, the control room had minimal measurements from these thermocouples upon which to rely for trends. It was also known that there had been a discrepancy between the values produced by two different types of thermocouples. Which type was operational on March 25, 1998 is unknown. The evidence also indicated that there was a discrepancy between the thermocouple skin temperatures and those measured through infrared and pyromatic techniques. ERA in its recommendations stated:

> Given the uncertainty in the measured temperatures, it is strongly recommended that the tube operating temperatures be verified by pyrometric measurement. If pyrometry indicates that the actual temperatures are significantly different from the assessment temperatures used in this analysis, refined calculations can be performed (under the scope of this contract) upon supplying such temperatures to ERA Technology.

In spite of this caution, little evidence of verification of tube operating temperatures was presented at the inquiry. The uncertainty as to the actual tube skin temperatures was not adequately addressed after the ERA report in spite of the fact that NARL testified that it relied on this report for its understanding of the remaining tube life in heater 1401. The evidence of infrared measurements that were tendered clearly show higher temperatures than those reported by the thermocouple measurements. These infrared measurements indicated skin temperature of 1000-1100°F. These temperatures are over the recommended operational limit of 900°F recommended by ERA and significantly over the designers "maximum skin temperature" value limit of 771°F. The Shell report noted that since January 1997, the highest reported tube wall temperature reported by thermocouples was 525°C (1027°F). It notes that the tube skin temperatures as reported, had been below the scaling temperature for 5Cr ½ Mo tubes (650°C or 1200°F). However, this does not mean that the scaling does not take place as it may be that the thermocouples available at these two locations in heater 1401 were not be at the locations of the highest heat flux or where the flame impingement takes place on the tubes, this is particularly so after the realignment. Pictures taken immediately after the incident show signs of scaling on tube 9 close to the location where the tube fractured. Innova found evidence of scaling at the fracture point. All this information, other than that found by Innova's metallographical analysis, should have been known from information readily available to NARL before March 25, 1998. No priority was given to increase the number of proper thermocouples and placing them so as to cover all passes in the heater in particular in those areas which received increased heat flux after the realignment of the burners.

7. <u>Inadequate skin thickness measurement procedure</u>

The tubes in heater 1401 operate in a very hostile environment. They operate at high temperatures, high pressure and in the presence of corrosive chemicals for long periods of time. The useful life of the tubes is affected by this environment. A critical part of the continued safe operations is to ensure that the tubes are replaced as they age and before failure. Proper planning ensures that the tubes are replaced or repaired before they fail. Detailed information as to the condition of the tubes and a planned ongoing replacement program is necessary. The information should include measurements of the remaining wall thickness of the tube, evidence of overheating, stress or damage, and evidence of the ongoing operating conditions that may affect the interior or exterior of the tube. The wall thickness of each tube is known when it is new as is the minimum wall thickness required to continue operating the tube. The original tube wall thickness of tube 9 was 0.258 inches with a minimum retirement thickness of 0.133 inches. The following wall thickness measurements were taken of tube 9.

	Type of NOE	NOE Performed By	West U Bend	West End	East End	East U Bend
Sept. 14, 1989	UT	NPL	.258	.278	.277	.295
Oct. 26, 1991	UT	NPL	.253	.252 .237	.287 .299	.398
Aug 27 1992	UT	NPL	.241	.254 (? where)		.374
1993	UT < BHN	NPL	.257			
BHN 198 7 feet from east end.						
Nov 16, 1995				.243		
Nov. 12, 1996				.252		

These are the only UT and BHN measurements that were placed into evidence at the inquiry. In 1996 ERA received the “complete UT data from the south wall radiant tubes from 1987 to present (1996)”. It appears that no other data was forwarded to ERA on tube wall thicknesses at that time. NARL had no data for operations for operations in the 1970's. The wall thickness calculations made by ERA in 1996 came from a tube installed in 1993. The above information appears to be that the total information as to wall thickness in tube 9 that existed up to late 1996. The only other wall thickness measurement made on tube 9 after November 1996 was in January 1997 when a reading of .226 was made at an unknown point on the tube. Evidence at the inquiry indicated that accurate specific measurements taken regularly (by properly calibrated UT or other acceptable measuring devices) at set points on the tube is the proper method of determining tube wall thickness. No such procedure was put in place by NARL before March 1998. Curtis Williams, although given no clear instructions to do so, wanted to implement parts of API 530 code concerning tube life calculation in 1996. He intended to use that code to develop a tube life program based on corrosion rates. When he left QC in 1997, he was still determining base line information. He testified that some students also tried to develop a corrosion rate program in late 95, however, nothing came of the initiative. Although API 530 does not cover "fired heaters" (they were outside the scope of the code) he planned to develop a program based on the principles of the code. As part of program development, he purchased a computer program to record and analyze thickness measurements, however, the computer program did not work and it was not replaced. He testified that at that time, 94-97, "visual inspection" on shutdown was used to determine remaining tube life. Another employee testified that in considering UT and other tube thickness measurements, "there was no confidence in the information they returned." The erratic tube wall measurements, some above the original thickness of the tube wall and others increasing from year to year, were readily apparent to NARL. This either indicates improper measurement, improper calibration of the instruments doing the measurement or that the measurements include scale or other internal or external build-ups. When all this evidence is considered, it is clear that NARL had no credible information upon which to determine remaining tube life calculations. ERA, assuming the information it received from NARL was accurate, based its calculations on inaccurate measurements. It is clear from the Innova analysis of tube 9 that the wall thickness had deteriorated well below the minimum required thickness to continue operation by March 1998. Tubes do not reduce in wall thickness at a set rate in any tube. Different areas on the tube may have different reductions in thickness. However, accurate measurements made at set points on the tube on a regular basis can provide critical additional information to engineers calculating the remaining life of the tube. It is unfortunate that NARL did not introduce such a measurement of tube thickness procedure before March 1998. In combination with other factors it may have caused the tube to be replaced before the incident that killed Jerome Kieley and James Mercer.

8. <u>Tube remaining life calculation</u>

In 1996, Curtis Williams, based on information he then had, prepared a tube life fracture analysis for heater 1401. His initial calculations found that a tube wall corrosion rate of .30 mpy (mils per year) for the lower radiant tubes. However, using process date for the period 30 September 1994 to 14 November 1996 he reduced the rate to 13 mpy. Taking information for the period June 1987 to August 1992 he calculated the long term corrosion rate in both the lower and radiant sections at 10 mpy. In presenting his report he emphasized that small temperature excursions from the norm should be avoided as the effect of a temperature increase on the remaining life of the tube would be cumulative in nature. Using 595°C the corrosion rate was estimated at 10-15 mpy but at 675°C the rate would be 20-30 mpy. He did not take the sulphur content in the crude into consideration in making these calculations. I have already commented on the problem with ERA's calculations and merely state that they were based on the information provided by NARL and a sample of tubing from the newer tubes, and ERA assumed that the information obtained from the 1993 tube applied to all the other tubes as did NARL. The evidence at the inquiry shows amongst other factors that in 1997 heater 1401 was run over design capacity, above the recommended skin temperatures, at a very high viscosity and with a higher sulphur content in the crude. The heater group were aware of all of these factors. Their duties included heater efficiency and maintenance. Knowing the contingencies in the Curtis Williams report and the limitations in the ERA report concerning operational temperatures and corrosion it is inconceivable that the heater group, senior management and processing relied on the tube life remaining calculations made by Curtis Williams and ERA. The Shell report notes that considering the operating conditions of heater 1401, it is not surprising to find a very short life time remaining in the tubes. Shell using the remaining tube life calculations described in API 530 (the same calculations used by Curtis Williams in 1996) calculated that the actual life remaining in the tubes in early 1997 was three to five years. This indicated a wall thickness loss of 13 mpy at 547°C. This agrees with the calculations of Curtis Williams. The Shell report encapsulates the whole situation in a nutshell we it says:

> The tube that has ruptured in 1998, tube no. 9 from the bottom, has not been replaced in the last 6 years. Part of its life time had already been consumed, although the tube bad not been exposed to the highest heat flux until 1997. However, since beginning of 1997, when the in-line burner pattern was introduced, the peak heat flux has increased in the region of tube rows 7-9. In addition, a higher than normal corrosion rate has been observed (measurements by the Q/C department).
>
> If we now assume that the skin temperature has been around 500 °C (932 °F) and that the corrosion rate has been 13 mpy over 6 years prior to the failure, and that the remaining life amounted to 43 years at the beginning of 1997. By increasing the tube wall temperature to 547 °C as a consequence of the relocation of the burners and a corrosion rate of 13 mpy (conservative), it can be calculated that the remaining life is zero after one year of operation at those conditions.
>
> In conclusion it can be said that the tube rupture in tube no. 9 can be explained. Most unfortunately, an in itself good modification, being the relocating the burners, has contributed to this failure of the tube.

10. Tube metal selection

It became apparent to the inspection and QC departments at NARL in 1996 that 5% chrome 0.5% Moly tubing was not adequate for NHT service heaters. Curtis Williams, Robert Stacey et. al. all recommended that the tubing be upgraded to at least 9 chrome. In 1997, ERA says in their report:

> **8.1 Alternative material Selection**
>
> The current material recommendation for refinery equipment operating in environments containing hydrocarbons + hydrogen and hydrogen sulfide of greater than 0.01 mol% at temperatures greater than 550°F is Types 321 or 347 stainless steel (Reference 1). This recommendation obviously refers to equipment exposed to a sulfur-containing feed that is downstream of the point of hydrogen injection as is charge heater H-1401. With sulfur contents in the H-1401 feed ranging up to 1000 ppmw (1% by weight), this environment would require the use of 321/347 stainless steel if the current recommendation were applied.
>
> Despite the literature recommendation, the use of 5CR½Mo low-allow steel appears to be adequate for this application. This conclusion is based on the assumption that the ultrasonic thickness measurements are accurate. There is no reason, at the present time, to automatically disbelieve the thickness measurements despite the noted anomalies. In fact, micrometer, measurements of the test tube indicated a remaining wall thickness of 0.238 inches.
>
> Upgrading the tube material will not have a beneficial effect in terms of resisting the effects of local overheating. As shown in Table 6 the elastic allowable stress does not increase significantly with material upgrades and in fact it will occasionally decrease.

> Upgrading the tube material from 5Cr to 9Cr or 12Cr will, however, have a beneficial effect on the corrosion resistance. Given that the current operating parameters and feed composition will continue into the future, the use of a stainless steel would not appear to be warranted. If corrosion rates increase in the future, upgrading the tube material to 9Cr or 12Cr should be considered. At corrosion rates of 10 mils per year of higher tubes fail prematurely by wall thinning (Table 13).

One of ERA's recommendations was to "upgrade the tube material from 5Cr to 9Cr is recommended if the corrosion rates increase much beyond the current assumed rate of 5mils per year." With Curtis William's calculations, ERA's recommendations, the cautions and recommendations included in both and knowing that the operating conditions that existed at the refinery in late 1997 and early 1998, it is again inconceivable that NARL management did not act on this recommendation. The existing operational conditions clearly indicated that the tubes should be upgraded. Even on the scheduled May 1998 shutdown, the tubes were not scheduled to be upgraded only "cleaned". The only explanation given at the inquiry by senior management and the heater group as to why this recommendation was not carried out was that "we relied on the ERA report". If any reasonable person read the recommendation and reservations in the ERA report concerning the tubing and knew of the "real" operating circumstances of heater

1401 in 1997-1998, they could not reasonably make such an assertion.

11. Perforation in heater casing

Heater 1401 was designed as a closed structure. The only air entering the heater was carefully controlled by louvres around the burners. All the fired heaters in the refinery, including heater 1401, were originally lined with a concrete-like cast refractory. In heater 1401 this internal layer was five inches thick. That refractory provided thermal insulation to improve the efficiency of the heater, as well as a smooth surface from which radiant heat could be reflected somewhat to the non-fire sides of the tubes. No refractory was supposed to fall on the tubes and cover or insulate them. Of particular significance, is then, the cast refractory was impervious to the products of combustion and thus provided a protective barrier for the inside of the metal casing panels. In 1987, Newfoundland Processing had the solid refractory removed from all the fired heaters and replaced with a ceramic fibre blanket insulation. In concept, this is similar to the glass fibre insulation commonly found in homes. The generic ceramic fire blanket installed by Newfoundland Processing (referred to as Kao Wool) was light, had excellent insulating properties, and was easy to install. The owners were apparently pleased with the switch over. One significant disadvantage of the ceramic blanket, however, is its porosity which allowed the products of combustion to percolate through the material. It is particularly susceptible to the passage of sulphur dioxide and sulphur trioxide which, along with other deleterious gases, are commonly found in combustion products of most common refinery fuels. It is thus inevitable that such gases will pass through a ceramic blanket and contact its backing plate. In the case of the Come-By-Chance refinery heaters, that backing plate was carbon steel. In the presence of water, sulphur trioxide converts to sulphuric acid. Sulphuric acid is exceedingly reactive with such metals as iron. To place the ceramic blanket insulation in fired heaters which are formed with carbon steel panels, and which are using a sulphur bearing fuel, is thus a predictable and foreseeable recipe for disaster with respect to the integrity of the casing panels. (Per Tupper report p. 82). To many refinery operators in the 1970s and 1980s, this was an acceptable risk of doing business, as they postulated that the casing holes served only to reduce the efficiency of the heater. In time, however, those operators including NARL came to realize that the casing holes had a direct and deleterious effect on the heater tubes, for:

1. The holes admit air and moisture
2. That air needs to be heated, so that the heater duty and the burner load are increased

3. Under certain dew point conditions, the moisture reacts with the sulphur trioxide to produce more sulphuric acid which makes more holes
4. The extra "tramp air" disturbs the draft and flame pattern in the fire box, particularly on windy days
5. The rogue draft pattern adversely affects the burner flame pattern and promotes flame instability, which can lead to flame impingement on the tubes
6. Flame impingement significantly reduces the useful life of alloy tubes, particularly those made of 5Cr
7. The tramp air promotes accelerated external corrosion on the heater tubes
8. In the event of escape of hot explosive gases or fire, it permits such gases or fire to escape through holes rather than be contained in the heater.

In addition, refiners found that the blanket was friable and would fall off. This would reduce the insulation effect of the firebox, and, if it landed on the tubes, could shield portions of the tubing from the heat of the furnace. Evidence tendered at the inquiry showed that this was a common occurrence and a real problem in heater 1401 for several years before 1998. Many refiners soon reverted to solid refractory as they realized these disadvantages with the ceramic blanket. The evidence introduced at the inquiry shows that when NARL bought the refinery in 1994, they recognized that the casing holes due to sulphide corrosion was a problem with their heaters. As a consequence, they instituted a phased program of replacing the heater panels. However, in the interim, they kept replacing when necessary, the kao wool insulation as it was damaged and/or fall on the tubes or onto the floor of the heater. As a result, the holes in the casing in heater 1401 kept increasing in number and size to a point requiring aluminum tape to be used to cover the holes to prevent access of outside in into the heater box. Heater 1401 was scheduled for panel replacement during the May 1998 shutdown. Unfortunately, as we know the heater did not make it to that shutdown. Several employees of NARL, including some management personnel, described heater 1401 in March 1998 as being in deplorable condition. Other employees viewed the condition of the shell as dangerous and they were concerned when working on that heater. One employee recalled being told to stay off the roof (hip section) because it was so dilapidated and rusty that you could poke a hole through it and you may fall through it into the heater. There is no doubt that the holes in the casing of heater 1401 contributed to external tube corrosion, flame impingement on the tubes, and reduced the overall efficiency of the furnace. It contributed to the heater being run “harder” in order to achieve a temperature increase in the feed from the inlet to that required at the outlet. One disturbing result of holes in the heater casing is the effect that it had on the injuries suffered by James Mercer on March 25, 1998.

Immediately after the heater burst, James Mercer, due to his location on the heater, was bombarded by jets of pressurized hot hydrogen rich hydrocarbon vapor and instantly enveloped in a cloud of those vapors. Those jets continue to feed through the casing holes adjacent to Mr. Mercer's position. When the vapor ignited, he would have been engulfed in a ball of fire and the fire from that ball would have flashed back into the heater. The heater would still have been operating in a significant positive pressure, so that the jets at 600 plus degrees Fahrenheit gas (for comparison note that the highest setting in the oven of a domestic electric range is 500-550°F) would have turned to small torches or jets of flame. Soon afterwards, the lower sections of the heater would have been put in a negative pressure and the air drawn into the fire box. Once flames were established therein, the resulting turbulence and convection currents would continue to draw air in through every crack and hole in the lower portions of the heater, while maintaining positive pressure and resulting expulsion of the hot flames in the mid and upper regions. That air would have supported combustion inside the heater. We know from the evidence that James Mercer climbed directly down from where he was located. On his way down the side of the heater, he would have been in the fire ball and subjected to more jets of a larger size because the holes in the lower panel were larger. It can therefore be said that most, if not all, of James Mercers injuries can be attributed to flame which resulted from the casing holes. As these holes contributed substantially to the production of a vapor cloud at and around Mr. Mercer and once the vapor ignited, jets of flame shot out of the heater through the holes at the area where Mr. Mercer was working and along his path of escape as he climbed down or along the face of the heater.

It is conceivable had the holes not been in the casing of heater 1401, there would have been no flame or less flame on the side of the heater where Mr. Mercer was working and he may not have been exposed to the extent that he was and hence may have suffered fewer injuries.

12. <u>Upline equipment fouling</u>

I have already addressed this issue as it effects the operation of heater 1401.

13. The type of heavy crude oil being refined

I have already addressed this issue in some detail as to how it effected the operations of heater 1401.

15. Safety training at NARL

When NARL took over the refinery in 1994, it inherited a refinery that had not been run in a safe manner. It was described as dangerous. NARL clearly recognized this situation and put in place a plan to make safety an important part of the work environment. Employees were hired solely for training and training programs were developed. However, the evidence from the inquiry indicates that the training was not, in most cases, made mandatory and its content was inconsistent. Two full-time employees at the operational supervisory level in 1998 gave evidence that they took no part in safety courses as a worker or foreman before 1998. Other employees testified that safety training was not given priority before 1998. The evidence indicates that NARL was moving slowly to address the lack of safety training, however, by March 1998, no detailed policy, procedures or safety training was required of employees and staff (other than fire technicians and first aiders). There was no job safety analysis system in place and the safe work permit procedure was not clear to employees and not understood by some supervisors. The hiring of Jamie Beach as safety supervisor in February 1998, one month prior to the incident, was the first concrete effort to co-ordinate the supervision of all safety training into one person.

16. <u>Safety and emergency equipment at NARL</u>

NARL inherited much of its safety equipment from NPL. In fact, between the years 1994 to 1998, NARL spent two and a half million dollars on new and upgrading of fire and safety equipment. By 1998, it was in the process of providing protective clothing to full-time employees (Nomex) and upgrading its emergency equipment. However, it is clear that safety equipment that should have been used was not always being used as it should. The designer of the heater required in its operating manual that all persons who were involved in lighting burners or looking into burners should have a full face mask when carrying out such duties. This is clearly laid out in the heater operating manual. However, this was not put in place until after the March 1998 incident and only then under a direction from Occupation Health and Safety. Before March 1998, contractors and non-permanent employees were responsible for their own clothing and footwear. Offsite contractors appear to have brought much of their own safety gear to the site without proper assessment of it being appropriate for the job which was being carried out. Some inspections were carried out by Occupational Health and Safety (OHS) inspectors but not very often. NARL did have fire extinguishers, bunker gear and other safety and emergency equipment onsite. However, as can be seen on March 25, 1998, its whereabouts where unknown or it was unavailable at a critical moment (no trauma kit, no phone to call an ambulance, no ERV outside of the laboratory, removal of injured persons by truck). The fact that the overhead monitors and fire truck hook-ups were delayed due to rusty valves and tight bolts is an indication that equipment, in general, was not inspected and kept in proper working order. It indicates a lack of overall planning and procedures at critical times. New equipment may have been purchased and things were improving, however, systematic problems were still readily apparent.

17. <u>Employee and supervisor/management training at NARL</u>

Without repeating the evidence in detail, it became apparent, upon hearing the evidence presented at the inquiry, that most ground level employees at NARL felt that they lacked proper training, especially in emergency response situations. One supervisor who appeared at the inquiry pleaded to receive more training. It was also apparent at the inquiry that while different areas of middle management had a good knowledge of their own particular area, they lacked an overall understanding of the operations and workings of the refinery. Decisions they made were made without understanding the full consequences to other areas of the refinery. Senior management appeared to have good intentions regarding safety training and employee education, however, the evidence tendered at the inquiry shows a lack of understanding between the employees and senior management compounded by a lack of training at the supervisory level. One employee stated at the inquiry, "up until this happened the upper management QC and frontline were in different worlds, not a lot of information coming down." This in turn, probably contributed to union/management deterioration of relations to a point where employees described the situation as "us" vs. "them" in the work environment. This can be seen in the minutes of the SHE committee where employees often brought up matters and it is apparent that they were only dealt with slowly and sometimes not at all. The level of training generally led to a lack of understanding of the duties and responsibilities of employees, supervisor, management and the union.

18. <u>Government inspection of refinery operations</u>

Occupational Health and Safety (OHS), a division of the Department of Environment and Labour, had jurisdiction over all work places in the Province of Newfoundland and Labrador in 1998. In March 1998, OHS was separate from Boiler and Pressure Vessel Inspectors (BPV) which was part of the Department of Government Services and Lands. At that time, there were three BPV inspectors in the Province of Newfoundland and Labrador. They were responsible for all boiler and pressure vessels for the whole province. All three were qualified by a national board.

However, none of the inspectors came from a oil refinery background. Evidence tendered that the Inquiry showed that the inspectors believed in March 1998 that they only had jurisdiction over the pressure piping in heaters and nothing else. On the other hand, OHS appeared to understand that the heaters contained pressure vessels and hence, where therefore in turn, the responsibility of the BPV inspectors. It is fair to say that the government agencies responsible for regulation of the heaters where in March 1998 not sure who had jurisdiction over heaters at the Come-By-Chance refinery. As late as July 2002, it had not been determined who had jurisdiction over hot work permits - was it the Fire Commissioner or Occupational Health and Safety. On every shutdown and upon any changes to the pressure vessels or the boilers, BPV inspectors became involved. On each shutdown, they carried out complete visual inspections of the tubes in the open heaters and when necessary conducted a cursory documentation review. The evidence shows that 90% of inspections by BPV inspectors were carried out at the time of shutdowns. Inspectors were also present at testing of new equipment or at start up of equipment to ensure that the pressure vessels that were installed were installed and working properly. Once the inspector was satisfied, he then gave a two year certificate of operation for each pressure vessel he had inspected. The certificate period had been one year prior to 1995. The certification on the tubes in heater 1401 was scheduled to expire in July 1998. At that time, an inspection would have been required at the nearest shutdown, probably in May 1998, in order to re-certify the tubes for a further two years.

The NARL Quality Control Manual was registered with the Government of Newfoundland after NARL took over ownership of the refinery. In 1995, Curtis Williams of the NARL QC Department, requested that NARL be allowed to implement API 510, an owner user inspection program. It would have taken one or two years to implement this program. Mr. Eastman (Chief Inspector) testified that the government was very interested in his request and he asked that a proposal be prepared by NARL. He testified that NARL never did get back to the government about implementing this self inspection procedure and only finally did so after the March 1998 incident. However, Curtis Williams, P. Eng., testified that he wrote to the government concerning a revision to the NARL QC manual on April 1st, 1996 and he began revising the manual at that time to include API 510. By early 1997, the amended manual had been submitted to government. However, it had not been approved prior to March 1998. The government would have recognized API 510 as part of the National Board of Boiler and Pressure Vessel Inspections Code (s. 4 of Boiler, Pressure and Compressed Gas Regulations 119/96) which would have allowed NARL to train employees to national board standards and to do certain inspections of equipment without the necessity of governmental inspector involvement. Under the pre 1998 NARL QC Manual (was approved by Government) NARL was permitted to carry out minor maintenance, alterations and repairs to equipment without inspection but subject to later audit, this included heater tubes. It in interesting to note that heater tubes only became part of the NARL QC manual in 1996. The BPV inspectors, who gave evidence at the Inquiry, testified that their inspections before 1998 lacked consistency and were not designed to pick up any anomalies or trends. Further, they were not experienced refinery operations and equipment, only in a very general way. Several witnesses testified that before March 1998, OHS inspectors were a rare site at the NARL refinery. The evidence indicates that OHS did not have the staff to carry out proper inspections concerning the general safety at the refinery. Further, there was very little interaction between the BPV inspectors and OHS inspectors. Similar to the BPV inspections, most OHS inspections were carried out during shutdowns. Due to the misunderstanding as regards jurisdiction over heaters, no OHS inspection of heaters was carried out between 1994 and March 1998. OHS received no information as the operation of the heaters. It is clear that other than shutdown inspections and BPV inspections for pressure vessels, few government inspections took place at the NARL refinery as regards heaters between 1994 and March 1998. The prime reason for the lack of OHS investigation was a lack of expertise concerning all refineries within OHS and in particular OHS had no knowledge of any ongoing hazard identification and risk assessment at the refinery. The March 25, 1998 incident had a drastic effect on th involvement of BPV and OHS inspectors at the NARL refinery. OHS did a detailed inspection of the refinery in 1998 (although not on audit). NARL requested and received permission of OHS to implement an Integrative Management of Risk and Hazards Analysis System which included the qualifying of NARL employees under the National Board User Program (NBUP) to inspect equipment. Three employees at NARL had trained on this program up to July 2002. Under the National Board User Program (NBUP), NARL was required to conduct inspections on all pressure vessels and equipment for half the remaining life of the tube or equipment to a maximum of 10 years. NARL exceeded this standard and voluntarily introduced a $^1/_4$ life to a maximum of five year standard, a much higher standard than required by IAPA. It will take NARL three years to implement the program (2001-2004). In the hands of trained and certified employees of NARL, inspections carried out under that program should be able to identify root and base causes of incidents and place an emphasis upon hazard identification and risk analysis. The program requires inspections to be required on a more consistent basis and requires the gathering of information and statistics to allow for trend analysis. NARL initially started implementing this program slowly in 2002. Over 40 items, deemed critical by OHS in 2002, had still not been addressed by NARL in 2003. Some OHS staff, as late as 2003, still had some concerns about the standards of recognition and evaluation of workplace hazards carried out by NARL under this program as late as 2003. However, once implemented, the safety management portion of the IAPA program will provide a combined system geared towards the identification, measurement, management control of workplace hazards and to ensure that the hazards do not contribute to loss. OHS and PBV inspectors now appear to be acting cooperatively in addressing issues at the refinery concerning heaters and PBV inspectors now have jurisdiction over any factors that may affect the tubes in the heater and consistently review the operating statistics on a regular basis.

It is interesting to note that a senior engineer at NARL described having government inspectors onsite as, “a learning experience”. Employees at NARL were consistent in their testimony that the presence of OHS inspectors compliments the attempts by NARL to instill a culture of safety at the refinery. That is an important feature of the IAPA program instituted by NARL in 2001 and hopefully will be completed within the next few years. It is fair to say that NARL and government inspectors have come a long way since March 1998. While it can not be said that more government inspections could have prevented the March 1998 incident, it can be said that if more credible and informed inspections had been performed, it may have caused NARL to become more aware of the weaknesses in their hazards and risk identification program that were apparent in the years leading up to the March 1998 incident. The present self-inspection program being carried out by NARL is also used in other provinces and other refineries and it has a record of being effective and efficient in attaining its intended goal.

NARL rightfully made much of the culture of safety that it has attempted to instill in the work force at the refinery since March 1998. The completion of the IAPA safety program is a major part of the attempt to improve the safety culture at the refinery. We must remember, however, that no system can guarantee safety once and for all. It is necessary for NARL to cultivate a state of continuous mindfulness of the possibilities of disaster. This has to be done individually with employees and also with managers, especially senior managers. If a culture of safety is to be a mindset and a key to preventing accidents, it is also a management culture as well as an employee culture that is relevant. It requires a management mindset that every hazard will be identified and controlled and requires management commitment to make available whatever resources are necessary to ensure that a workplace is safe. Even if it means, on occasion, a large scale financial undertaking or even redundancy (which means the capacity to react if an event does arise). All employees in high risk industries require a (collective) mindfulness about the possibility of disaster. It should be recognized both at the government level and a management level that the technology of an oil refinery is so complex and integrated that it is beyond the training and understanding of operators, safety and maintenance employees. However, regardless of what position they hold in the operations at the refinery, it is an important part of the work of an employee at the refinery worksite to identify hazards. This is commonly called HazOp or a Hazard and Operability Study. All employee and management at a refinery should be provided with initial training in hazard identification. A HazOp ensures that work or equipment use is looked at systematically imagining everything that might go wrong and developing procedures and/or emergency solutions to avoid any potential problems. Since the incident of March 1998, some employees of OHS, as already noted, are concerned about the effectiveness of NARL's training and commitment to hazard identification and risk analysis. I make no finding as to whether or not this is a reasonable position to take but I do say that not only must the management of change be applied to all physical changes to the plant but hazard identification should also be applied to the existing plant in order to discover or address any latent conditions, often existing for some time, and in many cases apparently accepted as "normal". These "normal" conditions, in many cases, require ongoing HazOps. In effect, retrospective HazOps should be carried out as needed. The ultimate expertise and responsibility to identify major hazards lies with senior management and not with the employees. Safety culture must start from the top in order to make informed decisions and in order to make informed decisions, considerable thought has to be put into designing an incident reporting system that will capture relevant warning signs at every level of operation. As I have already described, before March 1998, there were warning signs: some were ignored, some were allowed to be left around in one department and others were not passed up the line. Those reports that did reach the SHE committee were often acted upon slowly. This cannot be allowed to happen again. The IAPI program being implemented by NARL and approved by OHS, which includes management change, is a good start to remedying the pre 1998 problems concerning hazards and risk identification and since its inception to date it has contributed to a significant decrease in accidents and injuries at the refinery. The important point to remember is that the safe operation of the refiner is responsibility of not only NARL but also the relevant government departments with jurisdiction over NARL's operations and equipment. Co-operation has started and it must continue.

19. Training of contractor employees working onsite

Before 1998, NARL was responsible only for its own employees onsite. NARL also hired outside contractors to carry out work at the refinery particularly at shutdowns. Many of the employees of the contractors had little or no training in refinery work or operations. The employees were allowed to enter a potentially dangerous work environment with little or no training or work experience. Statistics of injuries at the refinery shows that employees of outside contractors had a consistently higher accident rate than employees of NARL. Prior to March 1998, only NARL employees were subject to the provisions of the SHE manual as it was a union/management run procedure, and the SHE committee, therefore, had no jurisdiction over the employees of outside contractors. Any OHS orders or directions were sent to NARL, not to the contractor. However, this is now changed. Since 1998, the orders or directions are sent to the contractor and only if they are not complied with, does NARL become responsible. The lack of awareness of hazards and work protocols by outside contractors and employees has now been addressed to a certain degree. NARL has put in place, a recognized safety program that covers all the operations of outside contractor employees. All outside contractors who do work at the refinery are now subject to that program. All employees, including those that come onsite with outside contractors, must now undergo an orientation program before working onsite and both NARL and OHS both regularly inspect and monitor all outside contractor employees. This insures that all outside contractor employees have the proper equipment, follow proper work protocols and are able, to a certain degree, to identify hazards and risks in the environment in which they are working. Although not to the same level as NARL employees, the results of this program have resulted in a reduction in workplace incidents involving outside contractor employees.

20. <u>Safety planning not included in long term and project planning at refinery</u>

The evidence at the inquiry indicated that before March 1998, safety employees had no involvement in the planning of work or the purchase of equipment. The knowledge of safety personnel was often not put into the decision making by planners and purchase managers in carrying out their duties. Purchase managers and planners determined whether or not planned work or equipment were in compliance with safety. Planned work was sent down the line to be carried out. Safety only became involved at the level of the safe work permit. The safe work permit system was, according to the evidence before the Inquiry, not fully understood by employees or the supervisory level. The ultimate goal should be to have the safety factor included from the earliest planning stage in decisions regarding planning and equipment purchase. Part of the IAPI program is to instill in all levels of workers and management at the refinery, a sense of the importance of safety and to create a proactive rather that a reactive approach to hazards and risks. This safety culture has now been in place for several years. Safe work permits and procedures are now better understood and enforced and JSAs are now carried out on all jobs. These are two important improvements in the relationship and understanding between the safety department and planning. Each now appears to recognize the duties and responsibilities of each other and under the IAPA program, a concerted effort is now made to ensure that safety is involved from the very start in the planning and purchase of equipment. This was not the case prior to March 1998.

As can be seen in the March 25, 1998 accident, a normal accident is often so complex that the sequence of events leading up to it can not always be anticipated. Accidents may involve interactive multiple failures and are extraordinarily complex and the precise accident sequence are not always imaginable in advance and can be unpredictable. However, it is not necessary to predict the entire accident sequence in order to avoid it. The fact that one contributing factor had not occurred may mean that the accident would not have occurred. Most accident sequences are actually highly susceptible to interruption. Though sometimes unpredictable, it is often entirely preventable. Counsel for the families, in their summation, produced a very detailed chart in which they attempted to show the multiple factors involved in the March 25, 1998 incident. Its complexity and interconnectivity is, I believe, a true reflection of the complex series of factors that led up to the incident. It is difficult to say if one factor was the cause of the incident. We know that as a result of the rupture of the tube, Jerome Kieley and James Mercer suffered injuries that resulted in their death. Leading up to the rupture of the tube were a considerable number of factors, all interrelated, which at one point in time caused a catastrophic event to occur that resulted in the death of two persons. The events that led to the unfortunate deaths of Jerome Kieley and Jim Mercer are now in the past. As a result of the incident that caused their death, much has been learned by NARL, its employees and the government agencies involved. It is hoped that the finding of this inquiry and the recommendations that flow from these findings will contribute to a safer and more efficient workplace at the Come-By-Chance refinery and at all similar work sites in the province. Newfoundland and Labrador is potentially on the door step of petrochemical developments. It is hoped that the recommendations attached to this report will make the workplace at all future sites of petrochemical development safer places to work.

I wish to conclude, first by thanking NARL for its full co-operation in the carrying out of this Inquiry. No request for information was denied and free access to all staff and records was permitted without reservation. Secondly, I wish to thank the staff of Government Services and Lands and OHS for their co-operation and assistance. Thirdly, I wish to thank all counsel that appeared at this Inquiry for the professionalism and assistance in this long and complex Inquiry, especially Phillip LeFeuvre who was counsel for the Inquiry. I would also like to thank Allison Tupper, P. Eng., who provided engineering expertise to the Inquiry which was a great assistance in writing this report. Lastly, but by no means least, I wish to especially thank the families of Jerome Kieley and James Mercer who faithfully attended the hearings of the Inquiry. I hope this report will give them some solace in their grief and that it will help in a positive way in putting some sense of closure to this part of their lives.

RECOMMENDATIONS

These recommendations are made on the basis of the conditions that existed as of March 25, 1998. Many of these recommendations have been followed and implemented by NARL, the union(s) and employees of the provincial government.

1. Modify the inlet tubing to heater 1401 to ensure symmetrical lineup in one plane.
2. Upgrade the tube material in the radiant tubs of heater 1401 to at least 9Cr material. Upgrade to stainless steel tubes of A.321 type should be the long term goal, this would alleviate corrosion in the tubes.
3. Build a new NHT heater that can fire heavy RFO at acceptable efficiency and emissions.
4. Change the RFO from heavy to a lighter type of fuel oil.
5. Increase the temperature of the RFO to ensure the viscosity of the burners does not exceed 20CS.
6. Redesign the feed effluent heat exchanger train with the objective to achieve 100% vaporization of the inlet of the heater.
7. Consider designing an exchanger parallel to the A-Exchanger to facilitate online cleansing.
8. Reduce sulphur in the naphtha feed entering heater 1401.
9. Put in place a regular tube inspection protocol and procedure. The procedure should require UT, BHN and other appropriate measurement tests at specific locations on each tube (including all sides). The testing (to

include both destructive and non-destructive testing) should enable inspectors to determine at least the hardness, thickness and other relevant information required to determine internal and external condition of the tubes so as to enable an accurate remaining life to be calculated.

10. Increase the number of appropriate thermocouples on the tubes and connect them digitally to the control room. Ensure all non-working thermocouples are replaced as soon as reasonably practicable.

11. Install an additional screen in the control room for the purpose of trend analysis and emergencies.

12. Install fixed remote gas testers in the process areas of the refinery.

13. Put in place a regular infrared or other external heat measuring system or device, protocol and procedure to corroborate temperature measurements from thermocouples and other measurement devices.

14. Install O_2 measuring devices in the heater to determine accurately, the presence of rogue air.

15. Replace all existing steamer connections on hydrants with new style caps.

16. Ensure that a sample (two inches) of the microstructure of each new tube is obtained before it is installed. This will assist in determining estimates of remaining life of a tube during replica analysis.

17. Ensure that all calipers used for measuring tubes and other measuring equipment is calibrated on a regular basis and a procedure for ensuring accuracy is put in place.

18. A long term goal should be to connect all refinery instruments, digitally, to the control system in the main control room. If possible, instantaneous reporting of temperatures as opposed to a delay or average should be put in place.

19. Provide all console operators in the control room with a headset which does not require a cord or wire to be operated.

20. An automatic shutoff for all equipment should be available from the control room without the necessity of manual involvement (unless in emergency).

21. Implement a crack prevention program for all tubing and pressure vessels.

22. Consider a different sound alarm for fire, gas or accident/incidents and a general alarm for incidents involving more than one of these factors.

23. All members of the SHE committee should attend all scheduled meetings or perform assigned committee duties and shall not require supervisory consent to attend.

24. Each shift shall have at least two designated ambulance drivers and back-ups from different areas of the refinery.

25. All safety manuals and emergency response manuals shall be available online at all computer sites at the refinery. The employees shall be trained to access these sites.

26. That the safety department be provided with <u>all plans</u> before their approval in order to allow hazard and risk identification and assessment and if

necessary adjustments be taken into account for reasonably foreseeable hazards and risks before final approval.

27. A firehall employee should be a member of the SHE committee.

28. If reasonably possible, ensure that a safety representative be available to review all work permits and attend all JSA meetings before work is carried out.

29. All safety breaches should be reported regardless of union or management membership and all breaches placed on the employment record of the individual(s) involved.

30. One specific emergency radio channel be dedicated to contact between an incident co-ordinator and the control room.

31. All first aid personnel be equipped with hands-free headphone radios.

32. Long term goal should be to have <u>all employees</u> (where feasible) to be equipped with hands free wireless or radio.

33. All bunker gear and helmets should be color identifiable: first aid, green; fire technicians, red; etc. This will permit quick identification of all persons at any incident that occurs.

34. Occupational Health and Safety should consider hiring a risk assessment engineer with experience in petroleum and gas refinery, with work parameters to include petroleum and gas refineries, petrochemical and hydrocarbon exploration industries.

35. Occupational Health and Safety should consider hiring a full-time auditor to audit petroleum and gas refineries, petrochemical and hydrocarbon exploration industries.

36. Any planned work on, in or contiguous to equipment at industrial sites that could reasonably effect a boiler pressure vessel should be under the jurisdiction of Boiler Pressure Vessels Inspectors.

37. OHS should hire an inspector dedicated to petroleum and natural gas refineries, petrochemical and hydrocarbon exploration industries. The number of dedicated inspectors should increase as the industries expand in size.

38. OHS consider adopting appropriate API and other industry standards or procedures as part of the legislative framework but only after consultation with the industry.

39. OHS consider legislating a $^{1}/_{4}$ life five year replacement program for petroleum and gas refineries, petrochemical and hydrocarbon exploration industries unless an approved self inspection program is in place and then to a maximum of ½ life 10 years.

40. OHS to continue regular inspections and audits (with or without notice) of all worksites in particular the Come-By-Chance refinery.

41. OHS should legislate appropriate clothing and safety equipment for specific classes of employees who are employed or work in petroleum and gas refineries, petrochemical and hydrocarbon exploration industries.

42. All burner gun changes or burner adjustments be included in daily heater logs. All heater logs should be a centralized computer records system that is available to all employees.

43. All employees of NARL (or other appropriate industry) be required to personally sign-off as having been provided with and read all safety manuals and written procedures and all emergency manuals. All amendments or changes to safety manuals and written procedures or emergency response manuals should be provided to all employees before implementation. The amendments and changes (subject to emergencies) should only be implemented after all employees are trained and made aware of the effects of the amendments and the changes that the amendments might have to their job or duties.

44. All fire technicians and first aiders should attend and complete (on the employers time) annual upgrading and training.

45. At least two fully equipped emergency response vehicles and drivers be available at all times at different sites in the refinery. This will prevent the situation where both emergency response vehicles are in a building that is involved in an incident.

46. Back-up first aiders be available on each shift in the event that the laboratory is involved in an incident.

47. Trauma kits be readily available in all units at the refinery as well as in all emergency response vehicles, fire trucks and at the firehall and laboratory.

48. A dedicated trained emergency response team be available on each shift with clear identified duties and functions in the event of an incident.

49. Accident and multi-injury scenarios should be carried out on a regular basis.

50. NARL should complete the implementation of all IAPA safety programs to the satisfaction of OHS and continue to upgrade the programs as required by OHS.

51. OHS be given the legislative power to require an employer in a specific industry to implement national or certified programs concerning safety and operating procedures.

52. NARL and OHS co-operate in implementing a continuous certified self-auditing program for all equipment at the Come-By-Chance refinery.

53. NARL to continue cross-training whether with a Master Technician or a similar program, with the eventual goal that all persons working in maintenance, quality control and operations to have similar training and knowledge.

54. That <u>all</u> process engineers and senior management be required to take part in ongoing annual training in operations, maintenance, quality control and safety.

55. The heater group should receive all information concerning the operation, planning, quality control and maintenance of all heaters. All information received by the group should be placed in a readily available computer base that is accessible to all employees.

56. All reports, analysis and recommendations of the heater group be distributed to all persons involved in, dealing with or operating heaters.

57. NARL put in place a training program for all potential supervisors, lower and mid-level, to ensure that they will have the necessary management skills and knowledge to carry out management duties.

POSTSCRIPT

The purpose of this inquiry, as per its mandate, was to conduct an inquiry under the Fatal Investigations Act. The inquiry was not called for a specific purpose of determining the cause and origin of the fire that caused the deaths of Jerome Kieley and James Mercer, however, in order to determine the cause of the deaths, a considerable amount of evidence had to be considered about the background and circumstances surrounding the incident. Most of this report attempts to show the circumstances that led up to the March 25, 1998 incident that caused the deaths of Jerome Kieley and James Mercer. The recommendations relate specifically to circumstances as they existed on 5 p.m. on March 25, 1998. The Inquiry itself was held several years after the actual event. It is fair to say that the circumstance that existed on March 25, 1998, to a large extent, no longer exist today. Many of the recommendations have already been voluntarily implemented by NARL and OHS. Most of those that are not completed to date are in the process are being actually discussed or planned in the long term. Almost without exception, the employees and staff of NARL who appeared at the Inquiry, the staff of OHS and other persons praised the efforts of NARL in addressing and correcting the circumstances that led to the March 25, 1998 incident. It has been said that the Come-By-Chance refinery is now a show piece of safety and efficiency in the refining industry in Canada. NARL and OHS have come a long way since March 1998. For the record, I have not specifically noted which of the recommendations have been complied with and in the manner in which they have been addressed. That is not the purpose of this inquiry.