UNIVERSIDAD NACIONAL DE INGENIERIA

FACULTAD DE INGENIERIA MECANICA

"DETERMINACION DE LA PERDIDA ECONOMICA MAXIMA ESTIMADA POR RIESGOS EN UNA EMPRESA DE EXPLOTACION DE GAS Y PRODUCCION DE ENERGIA"

INFORME DE SUFICIENCIA

PARA OPTAR EL TITULO PROFESIONAL DE: INGENIERO MECANICO

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INDICE

Prólogo

El informe incluye el seguro de todo riesgo propiedades e interrupción de negocio (incluyendo Rotura de Maquinaria).

El objetivo principal del informe es el evaluar el control de la gerencia en las actividades principales tales como mantenimiento, operación e inspección. El PME catastrófico tendrá que ser reevaluado basándose en las actividades futuras y el incremento de operaciones del negocio.

Los Capítulos que se han decidido tocar son los siguientes:

- **CAPITULO II.** ***Memoria Descriptiva y Organización Gerencial:*** En este capítulo se estudia, las instalaciones de la planta y el manejo gerencial de la misma así como la estructura básica sobre la que se soporta la empresa.

- **CAPITULO III. *Exposiciones a Riesgo***: Se da a conocer los posibles riesgos que enfrentan las instalaciones, tanto naturales como los que pueden ser producto de un incendio o explosión.

- **CAPITULO IV. *Valores Asegurados***: Nos da a conocer los montos asegurados, lo que nos permitirá la obtención de la pérdida máxima estimada.

- **CAPITULO V. *Estimados de Pérdida***: Tema principal del informe, nos dá a conocer los posibles escenarios en los cuales se desarrollará la pérdida máxima estimada, tanto en su ocurrencia en daños a la propiedad como para la cobertura de interrupción de negocios.

- **CAPITULO VI. *Protecciones contra Incendio***: Nos brinda un alcance de las medidas con la que la empresa cuenta para reducir sus pérdidas o mantenerlas bajo control, y nos da una idea de la capacidad de la empresa para disminuir o prevenir un posible siniestro.

Además de esto en la parte final se pueden apreciar algunas conclusiones que se extraen de este informe y que deberían ser tomadas en cuenta en los análisis de este tipo de plantas.

CAPITULO I

INTRODUCCIÓN

El presente informe brinda un alcance acerca de todos los riesgos presentes tanto daño a la propiedad como Interrupción de Negocios incluyendo Rotura de Maquinaria.

1.1 El Riesgo

El Proyecto de Aguaytía es el primero en cuanto a utilización comercial de gas natural en el Perú y consiste en la operación de una planta de separación, una planta de fraccionamiento de líquidos naturales (NGL), una planta de generación eléctrica y las líneas de transmisión.

Comercialmente inicio operaciones en Julio de 1998.Tiene reservas probadas de gas para un estimado de 22 a 25 años.

La corporación Maple de Dallas, Texas maneja las operaciones de gas bajo contrato. Maple Gas también trabaja para PetroPerú y opera la refinería de petróleo de Pucallpa bajo una concesión a largo plazo otorgada por el gobierno Peruano. Duke Enginering & Services, Charlotte, North Carolina operan la planta de generación y el sistema de distribución bajo contrato.

La parte de gas del proyecto incluye la explotación por 40 años del yacimiento de Aguaytía, localizado en la selva central del Perú. Las instalaciones de procesamiento de gas cerca al yacimiento están diseñadas para extraer NGLs en cantidad de 60 millones de pies cúbicos por día de gas húmedo. El Gas natural residual y el NGLs producido son transportados por medio de un gaseoducto a una central de termoeléctrica de ciclo simple y a una planta de fraccionamiento en Pucallpa la cual produce 3800 barriles por día.

La energía Generada en la central termoeléctrica es transmitida a 220kV por aproximadamente 392 kilómetros en una sola línea de transmisión.

Esta cruza los Andes a una altura máxima de 4700 metros y une la planta de energía con el anillo eléctrico en la costa del Pacifico en la Subestación de Paramonga

El NGLs es fraccionado en la planta de Pucallpa, en un calentador natural de gasolina, la cual es alimentada desde una tubería por la

Refinería de Pucallpa, y LPG es almacenado en tanques a presión en el mismo lugar para luego ser despachados en camión hacia Lima.

No hay planes de expansión de las construcciones en el futuro inmediato, ya que la demanda de energía eléctrica y la venta de gas está por debajo de lo esperado.

Figura # 1 **Vista de la planta de separación de Gas en Zorillos.**

1.1.1 Equipos

Las plantas de procesamiento fueron construidas bajo los estándares más estrictos de seguridad tanto en los USA y todos los recipientes a presión están certificados por la National Board Certified. La tecnología del procesamiento de gas es convencional y se encuentra bien entendida.

La distribución de planta se puede considerar como buena, con los procesos en forma lineal y las fuentes de ignición como los calentadores de aceite están colocados lejos de las áreas de proceso.

Todas las plantas están equipadas con sistema ESD, el cual se activa desde el cuarto de control o desde el campo mismo por medio de botones pulsadores, los cuales cierran los ingresos y salidas a las tuberías. El sistema de quemadores tiene un alto estándar e incorpora un doble bloque que permite aislar el suministro de gas.

La posibilidad de que se presente sobre presión por vapor de gas es considerada mínima debido a la ausencia de congestionamiento o de áreas confinadas en las plantas. La mayor exposición se encuentra por parte de "jet fires" y "spill fires" originados en el sistema de calentamiento de aceite el cual opera cerca de su “flash point”. El LPG almacenado en Pucallpa y Manantay presenta exposición a “BLEVE”. El gaseoducto esta construido en zonas de jungla, lejos de las áreas pobladas. Esto refleja que la norma ASME B31.8 Type 3 solo afecta 1.5 Km. del total del gaseoducto. Un error de diseño de ABB Randall no tomó en cuenta el daño del CO_2 el cual causa corrosión lo cual resultó en una serie de modificaciones en las unidades de gas húmedo y la incorporación de equipos inhibidores de corrosión. El ratio de corrosión esta siendo monitoreado y controlado cada 15 días.

La planta eléctrica utiliza dos turbinas a gas ABB GT11 las cuales es parte de una flota mundial de 1100 unidades instaladas en el resto del mundo. La distribución de planta es buena con una excelente separación entre los servicios de generación, transformación y los turbogeneradores. Los transformadores están protegidos por un sistema de muros cortafuego y están ubicados sobre drenajes de aceite.

Con respecto a las líneas de transmisión, se considera que se encuentra bajo severas condiciones debido a los abruptos cambios ambientales debido al cruce de la cordillera de los Andes. Se realizan patrullajes de manera continua para asegurar el perfecto estado de las líneas de transmisión y en caso de necesidad corregir los desperfectos así como para retirar la vegetación de los alrededores.

1.1.2 Programas

La gerencia de Aguaytía Energy cuenta con una vasta experiencia en construir y operar platas eléctricas y de gas y ellos aparentemente despliegan un gran esfuerzo en lo que se refiere a prevención de riesgos.

El personal de operaciones cuentan con una gran experiencia ellos han trabajado en la industría del petróleo en el Perú durante muchos años, y han recibido un intensivo entrenamiento en plantas de gas de los USA. El uso de permisos de trabajo en todas las plantas fue calificado como bueno y el personal en los cuartos de control tiene el soporte de pantallas VDU que muestra los parámetros de los procesos, accesos a los manuales de la planta y a los procedimientos.

El personal de Maple en la refinería de Pucallpa provee de mantenimiento en talleres y equipos. Los programas de mantenimiento preventivo y predictivo siguen de manera estricta las recomendaciones de los fabricantes. Las condiciones de todas las máquinas es buena, cuentan con todos los sistemas de protección operativos. El orden es considerado como normal al giro del negocio.

En la planta termoeléctrica, los ingenieros residentes de PIC proveen de todos los procesos de mantenimiento e inspección en las turbinas de gas y los generadores. No existe un departamento de inspección formalmente establecido. Las inspecciones son llevadas acabo por el personal de mantenimiento y están centradas en la planta de gas donde en el ingreso del gas húmedo se detectó corrosión.

Maple Gas provee de los servicios de seguridad industrial a todo Aguaytía Energy y la actividad se desarrolla a buen nivel, con un comité mensual de ingeniería. Esto se refleja en la excelente estadística de accidentes en todas las plantas. La vigilancia es considerada buena en todas las instalaciones. El terrorismo ha disminuido notablemente durante los últimos años y se ha incrementado la presencia de las fuerzas armadas en la zona.

1.1.3 Control de Emergencia

Debido a la remota ubicación de las instalaciones la asistencia externa es limitada.

La excepción es la planta de fraccionamiento, la cual es asistida por el personal de bomberos de la refinería de Pucallpa.

Las protecciones contra incendio instaladas en la planta de energía y de fraccionamiento son adecuadas para el área de proceso y cuando fueron probadas funcionaron de manera satisfactoria. Igualmente la barrera de protección anti-terrorista alrededor de los tanques de LPG es considerada como aceptable, sin embargo los equipos de agua contra incendio pueden verse obstruidos por la misma barrera. Sin embargo la posibilidad de ocurrencia de un siniestro en esa área es baja.

La planta de gas no está equipada con ningún sistema de protección contra incendio, la única protección proviene de los extintores manuales. La posibilidad de aislar rápidamente el ingreso de gas húmedo y la salida del NGLs y gas residual por el gaseoducto, disminuye el riesgo de manera considerable. La planta se encuentra expuesta a daños de un potencial "spill fire" desde el sistema de calentamiento de aceite. Sin embargo todas las bombas incluyen un doble sistema mecánico de sello, el cual a su vez envía una señal de alarma al cuarto de control.

Todo el personal de la planta se encuentra entrenado en el uso de los equipos contra incendio y han recibido entrenamiento en campo en la refinería de Pucallpa.

1.1.4 Conclusiones

El proyecto incluye la extracción y separación de gas, el cual es utilizado para la generación de energía eléctrica, además del fraccionamiento del mismo para su comercialización directa. Un equipo experimentado se encuentra a cargo de los riesgos presentes los cuales son bien entendidos y controlados mediante la buena operación y mantenimiento de los equipos.

Aun así el proyecto es considerado de "Alto Riesgo" debido al giro del negocio.

1.2 Historial de Pérdidas

El riesgo sufrió la rotura de un álabe, en la turbina de la planta generadora en el año 2002 con una pérdida combinada de daños a la propiedad e interrupción de negocios por un valor de US$ 6`000,000.

1.3 Valores y Resumen de Estimado de Pérdidas

PMLs han sido calculados usando valores proporcionados por Aguaytía Energy. Esta referencia debe ser tomada en cuenta en el capítulo de Estimado de Pérdidas.

Valores de Propiedades declaradas (en US$) a 20 de Julio 2000 en las siguientes áreas:

Planta de Energía -Aguaytía	80 00,000
Sistema de Transmisión	79,325,000
Planta de Gas - Zorillos	31,185,000
Gas & NGL Gaseoducto	38,390,000
Planta de Fraccionamiento – Pucallpa	19,155,000
LPG Transferencia - Manantay	2,620,000
Equipo de Campo & Caminos	17,800,000
Maquinaria & Equipos	225,000
Vehículos	125,000
Equipos de Comunicación/Electrónicos	890,000
Maple Gas	12,353,000
Total	**282,068,000**

El PML de Propiedades y de Rotura de Maquinaria, considera todos los escenarios que se pueden presentar.

Los cálculos del PML están basados en el un 100% de "valores asegurables" que han sido brindados por el cliente y que reflejan el reemplazo de los valores existentes por la cobertura del seguro.

La interrupción del negocio está basada en la proyección de las ganancias en un periodo de 12 meses y están asociadas con los ratios de producción. Los actuales valores dependen de las condiciones del Mercado en el tiempo de la pérdida.

El valor declarado por Aguaytía Energy es de US$ 30 millones y Maple Gas US$ 10 millones sumando un total de US$ 40,000,000 durante 12 de actividad para el periodo 2004/2005. El periodo de indemnización es de 15 meses lo cual se refleja en el cuadro de PML que se expone a continuación.

	Escenario	US$ millones			Comentarios
		DP	IN	DP+IN	
Daños a la Propiedad (DP) PME	Sep. de Gas	18	40.9	58.9	15 meses
	Planta Eléctrica	15	9.4	24.4	15 meses
Rotura de Maquinaria (RM) PME	Planta Eléctrica	18	9.4	27.4	15 meses

CAPITULO II

MEMORIA DESCRIPTIVA Y ORGANIZACIÓN GERENCIAL

2.1 Planta de Procesos

2.1.1 Reservas de Gas

El campo de Aguaytía provee de las únicas reservas de gas húmedo a la planta de separación en Zorillos. El campo está ubicado a 6km de los pozos y a 4km de la planta, conectado por medio de una tubería de acero al carbono de 4" día.

En total hay 7 pozos de 2400 metros de profundidad, en el campo capaces de operar. Cuatro de los pozos son necesarios para abastecer el requerimiento de la planta eléctrica en horas pico. Los otros tres se encuentran disponibles para operaciones de reinyección cuando la planta eléctrica no se encuentra operativa. Esto maximiza la extracción de NGLs.

Todas las válvulas y seguros en la cabeza del pozo (Árbol Xmas) son operadas de manera manual. En la fotografía se puede apreciar el pozo Número 5 durante unas labores de mantenimiento, en las cuales se reemplazó la línea de flujo.

Figura # 2 **Árbol Xmas**

La presión en el flujo es de 2500 psi y la presión de cierre es de 3500 psi. El gas contiene un 2.8% de CO_2. La máxima capacidad de producción del campo es de 60 mmscfd.

La presencia del CO_2 ha resultado en la prematura falla de la línea del pozo No.5 en el año 1998 así mismo cerca a la planta de gas, el ácido carbónico ha inducido un proceso de corrosión. Por este motivo se ha tenido que revisar el diseño original de ABB Randall y tomar las medidas correctivas que han sido propuestas por los consultores especialistas (Metallurgical Consultants Inc.) contratados por Aguaytía Energy:

- La línea de flujo del pozo No. 5 ha sido completamente reemplazada con acero al carbono.
- Todas las demás líneas de flujo a una distancia de 150 metros de calentador de gas en la planta de separación han sido reemplazados por el mismo material.
- Los árboles Xmas y las tuberías de producción fueron reemplazadas en los pozos No. 5, 6 y 3 con tubería de cromo/níquel
- Se inyecta agentes anticorrosivos a cada pozo con la finalidad de proteger las líneas y reducir la corrosión a niveles aceptables.

Aguaytía Energy esta envuelto en un proceso de arbitraje en los US con Lummus Global para resolver el problema. A la fecha Aguaytia ha gastado US$ 1 millón corrigiendo estos errores de diseño y se espera gastar una suma similar en el futuro.

2.1.2 Unidades de Proceso

2.1.2.1 *Planta de separación de Gas*

El propósito de esta planta es el de separar los Líquidos de Gas Natural (NGL) de la fase gas. La capacidad nominal de la planta es de 60,000 mmscfd.

Se trata de una planta de procesamiento de gas estándar, que utiliza una tecnología bien conocida, la cual incorpora un turbo expansor Rotoflow y un enfriador de aluminio ALTEC para obtener una máxima eficiencia en el proceso y extracción de líquidos. La temperatura más baja en el proceso es de –90 ^{0}C y la mayor se alcanza en la parte superior del de-etanizador. El proceso de calentamiento por sistema de aceite opera a 340 ^{0}C y se enfría vía intercambiadores de calor fin-fan.

La separación del gas residual se inicia mediante la compresión a 1050 psig por medio de dos motores Caterpillar que mueven compresores reciprocantes Ariel de 1666 HP cada uno y abastecen una línea de 12" día hacia Neshuya. Ambos compresores son requeridos para abastecer los requerimientos de la planta eléctrica cuando ésta opera a un 100% de su capacidad.

En caso de que la planta eléctrica no se encuentre en estado operacional, el gas puede ser reinyectado al reservorio usando un par de motores Caterpillar con sus respectivos compresores Ariel de 2250 HP cada uno.

Las modificaciones llevadas a cabo como resultado de la corrosión por CO_2 incluyen:

- Reemplazo del ingreso de gas al Cooler con una nueva unidad de acero inoxidable.
- Reubicación y reemplazo del ingreso de la cabeza de gas húmedo con uno nuevo de acero inoxidable.
- Reemplazo de las líneas enterradas por una sola de gran diámetro en la sección elevada.

En adición, se ha programado un monitoreo de los espesores de las tuberías implementando 40 puntos de inspección tanto en el ingreso del gas húmedo en la planta de separación. Estos puntos de inspección fueron identificados por el consultor en corrosión y las muestras son monitoreadas cada 15 días.

Debido al incremento del nivel de humedad como resultado de la inyección del inhibidor de corrosión en las cabezas de los pozos, se ha recortado el proceso de regeneración del filtro deshidratador, lo cual estaría limitando la capacidad de operación de la planta. Se ha puesto en consideración incrementar el flujo de aceite caliente durante el proceso de regeneración mediante la instalación de una mayor bomba de recirculación.

Figura # 3 **Una vista panorámica de la planta**.

2.1.2.2 *Planta de Fraccionamiento*

El propósito de esta planta es separar los LPGs (propano y butano) de los NGL que se reciben de la planta de separación. Además la gasolina natural es separada y enviada por una tubería existente a la Refinería de Maple en Pucallpa. No hay almacenamiento de gasolina natural en la planta.

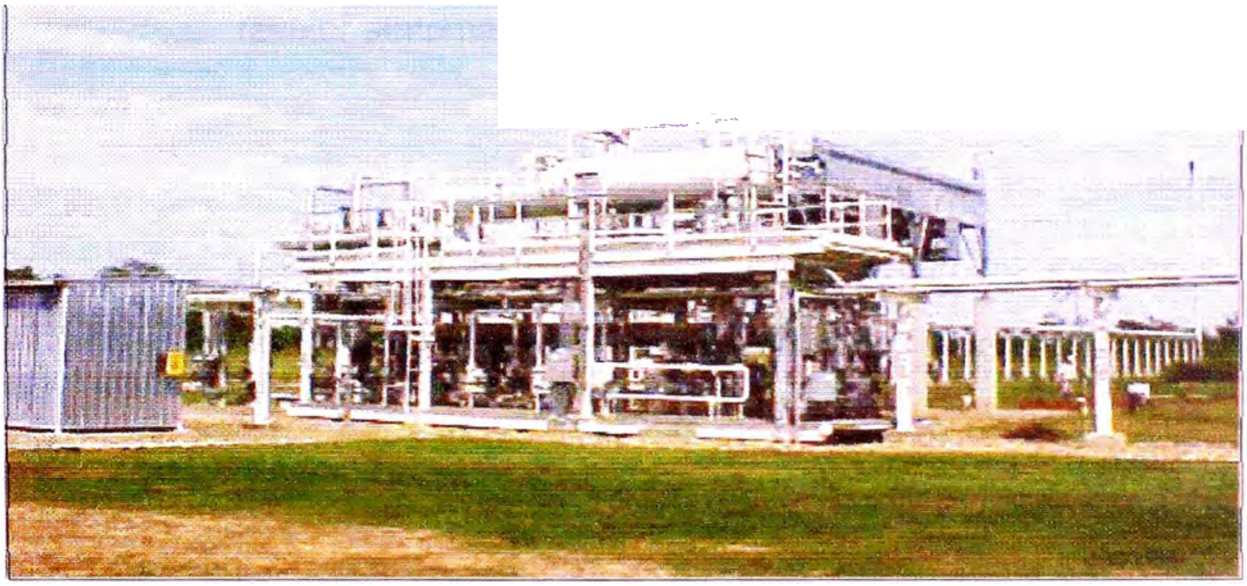


Figura # 4 **Vista de la planta de Fraccionamiento**.

La capacidad de la planta es aproximadamente de 3800 bpd y es de tecnología convencional. El proceso de calentamiento se realiza por medio de aceite que opera a 300 ^{0}C y el enfriamiento es vía intercambiadores de calor tipo fin-fan. Toda la planta cuenta con válvulas de seguridad y descarga hacia una remota y lejana antorcha que se puede ver a la derecha de la foto.

El NGLs entrante se almacena en un tanque a presión de 227 m^3. Desde ahí se alimenta por sistema de bombeado a la columna de fraccionamiento de LPG. Ahora que inyecta un inhibidor de corrosión en la planta de separación, no parece causar dificultades en ninguna parte del proceso. Los chequeos realizados en los recipientes a presión no parecen revelar síntomas de corrosión.

Los LPGs son almacenados en uno de los recipientes a presión de 227 m^3 desde donde son bombeados a dos puestos de despacho para los camiones tanque en los que son enviados a los consumidores finales en la ciudad de Lima. Esta instalación también puede ser utilizada para enviar LPG vía carretera a la estación de transferencia en Manantay.

La estación de transferencia de LPG en Manantay está localizada cerca y consta de 4 recipientes de almacenamiento de LPG similares al que se tiene en la planta de fraccionamiento, además de contar con una estación de descarga. Desde ahí mediante una tubería de 4" día.a lo largo de 7 kilómetros se envía el gas hacia las instalaciones portuarias de Pucallpillo. La instalación de transferencia de LPG no está siendo utilizada actualmente, por lo que no se almacena LPG y sólo se mantiene presurizada.

2.1.2.3 *Planta Eléctrica*

A menores temperaturas estas unidades pueden producir por encima de los 86 MW. Los generadores transformadores incrementan el voltaje desde 13.8 kV a 220 kV para luego ser la corriente enviada a la cercana subestación que cuenta con líneas de transmisión de 220 kV. Todos los switchgear están sumergidos en SF_6.

No hay combustible en reserva y no hay capacidad de almacenamiento. Un sistema de enfriamiento por aire es utilizado para disipar el calor producido por la turbina y el generador. No hay inyección de agua o vapor en el sistema de aire de la turbina.

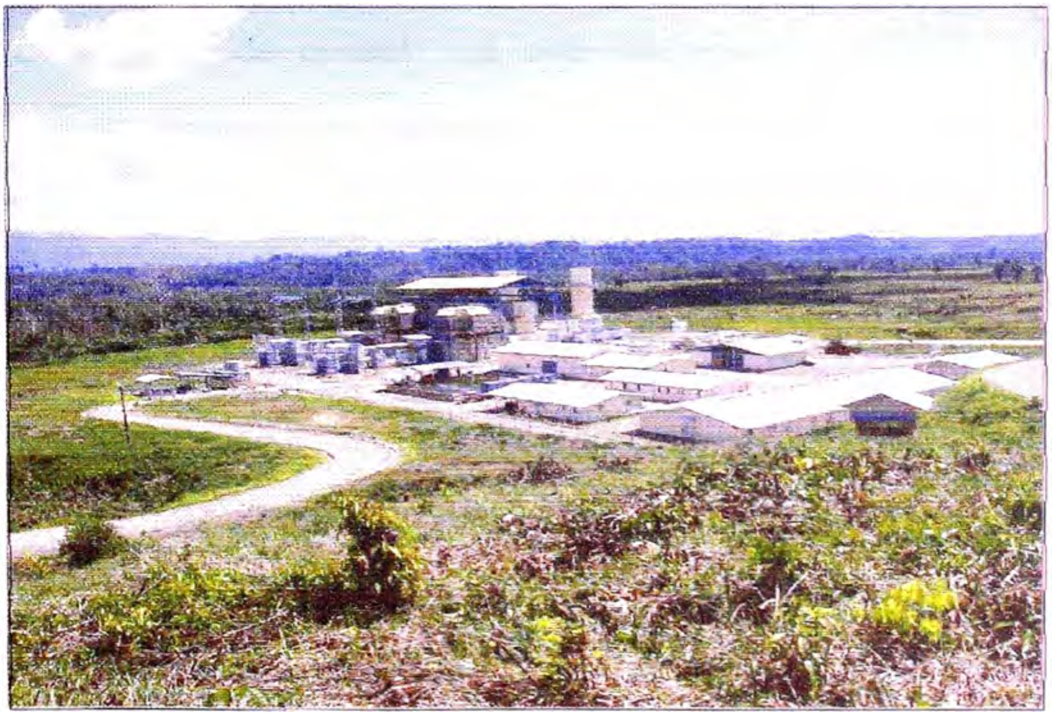


Figura # 5 **Una vista general de la planta eléctrica**.

La tubería de gas consiste en un separador de líquidos y un sistema de recepción, la experiencia durante las operaciones ha comprobado que se trata de un porcentaje bajísimo de condensado el que se recibe en la planta.

Cuando no se encuentra en operación las turbinas se les mantiene en rotación y el generador se mantiene caliente. El control y la protección de la maquinaria está brindado por el sistema ABB Egatrol 300 system que incluye monitoreo de vibración y desplazamiento de ejes.

El cuarto central de control monitorea la operación de ambas turbinas así como la subestación de 220 kV. El equipo del cuarto de control no está necesariamente para operar la turbina ya que cada una de estas puede ser operada desde una estación local.

En un acuerdo con la red nacional de despachos, se asegura la operación de las turbinas con una carga mínima de 40 MW por al menos cuatro horas, luego de lo cual se reduce a 6.5 MW por un máximo de 8 horas para luego volver a despachar 40 MW o más. Cuando se inicia un despacho, una parada de la turbina debe ser avisada con 20 minutos de anticipación, en caso contrario se sufrirán penalidades y multas.

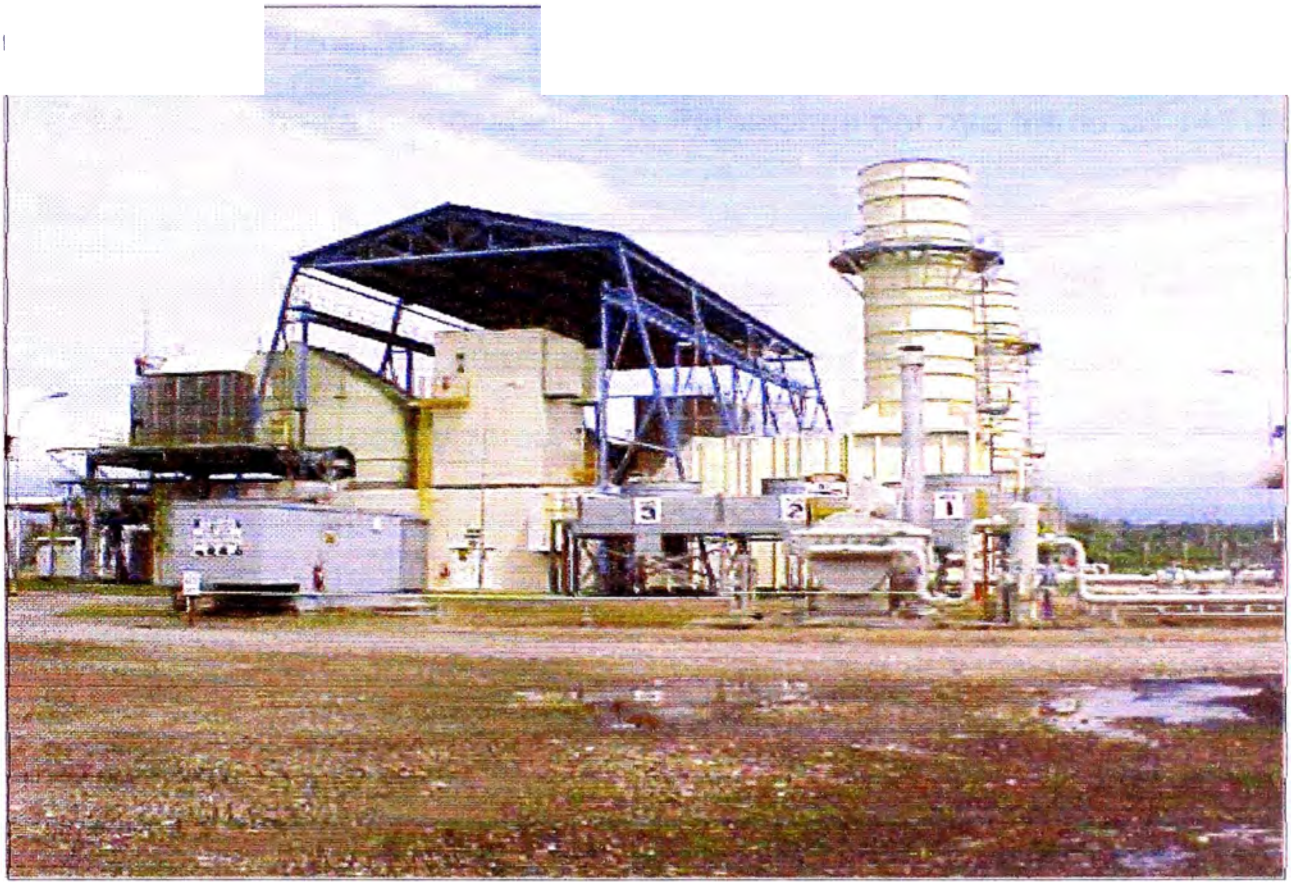


Figura # 6 **Vista panorámica de las unidades turbogeneradores**.

2.1.2.4 **Sistema** *de Transmisión de 220 kV*

El circuito simple de 220 kV Aguaytía – Tingo María - Paramonga es una línea de transmisión de aproximadamente 392 kilómetros de longitud que atraviesa diferentes zonas con diferentes condiciones climáticas, tales como la jungla tropical, las montañas y la costa, la altitud varía hasta en 4700 metros.

La línea consiste en tres segmentos. El primero va desde Aguaytía a la subestación de Tingo María a lo largo de 73 km.

El segundo sale de Tingo María hacia la subestación de Vizcarra a lo largo de 173 km. El tercer segmento continúa hacia la subestación de Paramonga por otro tramo de 145 km.

Los cables se encuentran suspendidos en estructuras metálicas, autos soportados en torres de disposición triangular con conductores y sistemas de protección apropiados. Los cimientos son independientes para cada pata de soporte.

La línea esta dividida en cinco zonas diferentes basadas en la elevación con respecto al nivel del mar y los cálculos que determinaron los tipos de protecciones y de aislamiento requeridos. Aisladores del tipo Fog han sido utilizados en las zonas costeras.

El total de estructuras instaladas asciende a 857, de las cuales 672 (78.4%) corresponde a estructuras en suspensión y 185 (21.6%) corresponde ha estructuras fijas. La separación máxima es de 458 metros, cada estructura está equipada con una malla de conexión a tierra de acero galvanizado. En el peor de los casos de conducción se encuentra en la montaña donde el diseño se ha basado en una temperatura mínima de $-10\ ^0C$, y una presión de viento de 45 Kg/m^2 y un máximo de espesor de hielo de 25 mm de radio. En estas condiciones aproximadamente el 70% de los conductores llegarían a tensión de ruptura.

Figura # 7 **Vista panorámica de la subestación Aguaytia**.

2.1.3 <u>Estado de las Operaciones</u>

Las *plantas de separación de gas y fraccionamiento* se encuentran operando al 100% de su capacidad máxima de producción de NGL.

No se espera incrementos significativos en la venta de gas, hasta que la planta eléctrica de Yarinacocha en Pucallpa no sea convertida a gas según lo acordado en el diseño original. La planta eléctrica es dependiente de los requerimientos de la red peruana y por el momento está siendo utilizada para cubrir horas pico. El periodo de operaciones de la misma suele ser la estación seca cuando la producción de las hidroeléctricas se encuentra en el mínimo. Gracias a la conexión con la parte sur de la red eléctrica peruana se ha producido un incremento en la generación de energía de la planta.

La disponibilidad de la planta en el año 1999 fue de 99.14 y 94.7 para los GT1 y GT2 respectivamente. Las horas de operación equivalentes (EOH) hasta finales de Junio del 2000 desde que se comenzó operaciones está mostrado en el cuadro inferior.

	Encendidos	Carga Rápida	Horas de Operación	EOH
GT 11	314	348	4,394	17,694
GT 12	415	412	7,355	23,895

En la línea de transmisión los disturbios en el año 2003 fueron causados en un 30% por árboles y el restante 20% por rayos. Los tendidos se consisten en columnas de 25 de área clara, según la regulación nacional, sin embargo esto es inadecuado por el tipo de jungla tropical en el que se encuentra el proyecto de Aguaytia Energy por lo cual se ha obtenido un permiso especial, y se está llevando acabo un programa de tala.

Se cuenta con 8 bypass de transmisión que permiten que la línea sea reparada en un máximo de 5 días.

Hasta el momento no se han dado casos de siniestros en la linea de transmición debido a fuertes vientos caída de hielo desde las montañas.

2.1.3.1 *Peligros Inherentes*

El peligro principal de fuego y explosión asociado con las operaciones de gas está centrado en el almacenamiento y procesamiento de LPG en los recipientes a presión de la planta de fraccionamiento.

Si bien es cierto que ambos procesos, hay suficiente LPG disponible como para generar una nube de vapor, que sin embargo debido a la falta de confinamiento o congestionamiento, en las áreas expuestas a sobre presión, en nuestra opinión no podrían.

El riesgo principal en ambos emplazamientos es el incendio en el calentador de aceite, el cual opera cerca de su flash point. Un punto a favor en el diseño es el relativamente bajo nivel de material inflamable, y la localización remota de las válvulas de emergencia, las cuales pueden ser operadas tanto desde una estación manual como desde el cuarto de control. El principal riesgo en la estación de medición en Neshuya y en la planta eléctrica es la misma naturaleza de gas en tuberías, que puede provocar jet fire en caso de una fuga.

Adicionalmente la planta de fraccionamiento y los almacenes de LPG en Manantay presentan exposición a BLEVE.

2.2 Sistemas Auxiliares

2.2.1 Vapor

No hay generación de vapor en ninguna de las instalaciones.

2.2.2 Electricidad

La planta de separación de gas genera su propia energía eléctrica por medio de dos 100 % redundantes motores generadores de 500 Kw Waukesha. La demanda máxima es de 250 Kw.

La energía eléctrica de la planta de fraccionamiento de gas se provée de la red pública por intermedio de Electro Ucayalí, vía un transformador.

La planta de energía eléctrica no cuenta con un sistema de arranque independiente por lo que necesita de las líneas de abastecimiento para el arranque de las dos turbinas. Sin embargo se cuenta con un generador a gas de 480 V de emergencia para abastecer la iluminación y los servicios auxiliares.

2.2.3 Agua

El proceso no requiere de agua, la cual es sın embargo suministrada mediante pozos profundos en cada local.

2.2.4 Combustible

El requerimiento de combustible para los calentadores de aceite, y el calentador de la planta eléctrica provienen del mismo abastecimiento de gas.

2.2.5 Aire

El aire de los compresores es 100 % rebundante y se provee en cada una de las locaciones según su necesidad.

2.2.6 Nitrógeno

Nitrógeno es usado para purgar los recipientes y las tuberías son adquiridas en cilindros a un tercero.

2.2.7 Efluentes

El tratamiento de los efluentes es suministrado en las dos plantas de procesos de gas mediante separadores API. Hay un separador de aceite agua instalado.

2.3 Recipientes

2.3.1 Recipientes sin Presurizar

Los almacenes al aire libre están limitados a pequeños 100 bbl tanques en ambos locales de procesamiento. Estos están ubicados en áreas individuales separados del resto del proceso.

2.3.2 Recipientes Presurizados

Los almacenes presurizados consisten en 18 x 227 m^3 recipientes de LPG en la planta de fraccionamiento y otros cuatro recipientes iguales en la estación de transferencia en Manantay.

Estos recipientes no están equipados con anillos de refrigeración, sin embargo se cuenta con monitores al principio y al final de los domos. Drenajes bajo los recipientes evitan la acumulación de líquidos en la parte inferior de los mismos, los recipientes se encuentran rodeados por pequeños montículos de tierra. Cada uno de los mismos cuenta con sistemas independientes de alarma.

Hay que anotar que los recipientes de Manantay no están siendo utilizados y sólo son mantenidos con presión de gas. Como se puede notar en la fotografía los recipientes están protegidos por muros de concreto contra ataques terroristas con cohetes. Estos evidentemente también cumplen con la función de muro cortafuego que permite focalizar el incendio.

Figura # 8 **Vista de los recipientes de Gas.**

2.3.3 Almacenamiento Refrigerado

No hay almacenes refrigerados.

2.4 Importación / Exportación de Equipos

2.4.1 Fluvial

Un puerto para carga de barcos LPG se encuentra disponible en las riveras del río Ucayalí en Pucallpa. Este consiste en una instalación flotante y flexible de carga en las riveras del río, sin embargo nunca ha sido utilizada hasta el momento.

2.4.2 Tren

No hay instalaciones de tren disponible.

2.4.3 Caminos

El LPG es exportado en camiones tanque diariamente que operan teniendo como base la planta de fraccionamiento. Los camiones tienen una capacidad máxima de 100 toneladas debido a la capacidad de carga de los puentes en la ruta. Hay dos puntos de abastecimiento en la planta ambos cuentan con cable a tierra, pero no hay indicadores o luces indicadoras disponibles.

Seis grandes camiones son enviados diariamente hacia Lima, además se cuenta con cuatro camiones más para el despacho local de LPG hacia algunas compañías embotelladoras del área de Pucallpa.

2.4.4 Tuberías

Todas las líneas de encuentran enterradas a 1.5 metros de profundidad a la derecha del camino y en la jungla se mantienen libres de vegetación los 12 meses del año, así mismo las inspecciones se realizan por tramos diariamente. Todos los cruces de río se realizarón mediante el modo de directionally drilled. La Máxima Presión de Operación en la tubería es de 1104 psig y la presión normal es de 1050 psig.

Todas las instalaciones poseen sistemas de lanzado y recepción de "chanchos". No hay válvulas de bloqueo automático instaladas en las tuberías, exceptuando el inicio y fin de cada locación. Las tuberías son operadas como parte del sistema ESD de la planta, todas las válvulas intermedias de bloqueo son operadas de manera manual. La tubería de gas es limpiada cada 15 días lo cual reduce la acumulación de condensado y disminuye la posibilidad de corrosión. Un inhibidor de corrosión es ahora inyectado debido a la sugerencia departe de un consultor debido a los daños iniciales ocasionados por el CO_2. La integridad de la línea se comprueba cada cierto tiempo utilizando un Tuboscope. Durante la última operación (2002) la línea se encontraba en buenas condiciones. El siguiente cuadro muestra las tuberías que interconectan las diferentes locaciones del proyecto. Las clases de la tubería están de acuerdo con el estándar ASME B31.8 como se indica.

Ruta	ASME B31.8 Class Type	Dia. (inches)	Distancia (km)	Ríos Cruzados
Zorrillos - Neshuya	1	12	37.5	Aguaytia, Uruya, Tahuayo
Neshuya - Aguaytia	1	10	83	Alejandro
	2	10	1.5	
Neshuya - Pucallpa	1	6	50.9	Neshuya
	2	6	3.6	
	3	6	1.5	

2.5 Layout y Construcciones

El proyecto ha sido diseñado y construido por ABB y sus subsidiarias (Lummus Global, ASESA) mediante tres contratos EPC. Dado lo inaccesible debido a las condiciones naturales las plantas de procesamiento y la de generación eléctrica fueron construidas en los US de manera modular, para facilitar el montaje y transporte. El de-etanizador y la columna de fraccionamiento (29 y 21 metro de largo respectivamente) fueron enviadas completas mediante barco vía el río Amazonas.

Graña & Montero, quien es un reconocido constructor en Perú, se encargo de la erección y el ensamblaje. Se procedió a una estabilización intensiva del terreno y a la construcción de fuertes cimientos de concreto. Las dos columnas fueron colocadas en medio de dos grandes monoblocks de concreto.

Los recipientes de proceso fueron todos construidos en los USA bajo los estándares ASME VIII (National Board Certified).

El diseño de la planta y la distribución de la mısma se pueden considerar como bueno debido a la localización remota de los calentadores de aceite con respecto a las áreas de proceso y las líneas de abastecimiento. Las líneas de interconexión están por lo general a nivel del suelo. La casa de compresión es una construcción abierta que impide la concentración de gases inflamables como se puede notar en la fotografía.

Figura #9 **Vista de Casa de Compresión**

El almacenamiento de LPG en la planta de fraccionamiento está ubicado a una distancia de 60 metros del área de proceso. Los recipientes están ubicados en doble línea con el final de los demas lejos del área de proceso. Los cuartos de control están por lo general ubicados a 60 metros de cualquier proceso. Además las reservas de agua contra incendio y el sistema de bombeo esta localizado a buena distancia. Además hay una buena separación entre la planta y el cerco perimétrico.

Por el hecho de estar montada sobre bloques, la superficie aledaña a los procesos no se encuentra sellada y no hay sistema de drenaje subterráneo. El agua fluye de manera natural sólo mediante una ligera inclinación fuera de las áreas de proceso.

El ingreso de gas húmedo está localizado a 30 metros afuera de la casa de compresión lejos de cualquier exposición de la misma en caso de un jet fire. Las instalaciones de mantenimiento de tuberías están bien ubicadas en todas las locaciones.

Todos los enfriadores del tipo fin fan están equipados con protectores contra vibración. Las bombas de aceite y de LPG están equipadas con un doble sello mecánico provisto con alarmas que son monitoreadas desde los cuartos de control.

2.6 Sistemas de Seguridad y Control

2.6.1 Filosofía

El control de procesos es un PLC Allen Bradley basado e incluido en el ESD, el cual es totalmente integrado. Se cuenta con un sistema de UPS instalado en las diferentes locaciones para mantener el control sobre operaciones esenciales en caso de falla de la energía. Una bien diseñada pantalla VDU muestra claramente las condiciones del proceso.

2.6.2 Cuartos de Control

Cada locacion cuenta con un cuarto de control individual el cual controla el área de procesos de manera remota. No es una construcción resistente a explosiones y no tiene un sistema contra incendios de protección incorporado. Hay que anotar que la planta de energía eléctrica puede operar sin el cuarto de control.

2.6.3 Sistema ESD

Las dos plantas de procesamiento y la planta de generación eléctrica están equipadas con un sistema ESD el cual brinda los parámetros de los procesos y es activado mediante botones en el campo. El sistema ESD opera a dos niveles, el primero es apagando por completo el proceso y el segundo es aislando las tuberías de ingreso y salida mediante válvulas servo asistidas. El sistema ESD esta diseñado para registrar menos de una falla por año. El sistema de protección de los turbo generadores esta manejado y se activa de manera automática mediante el ABB Egatrol 300.

2.6.4 Sistemas de Escape

Solo se cuenta con una antorcha elevada en la planta de fraccionamiento. Este equipo cuenta con sistema de encendido automático. No hay válvulas duplicadas instaladas. Todas las válvulas de alivio están aisladas del proceso mediante válvulas de bloqueo.

2.6.5 Aislamiento Remoto, Despresurización y Desfogue

Debido al limitado inventario en las áreas de proceso, no hay válvulas de aislamiento o de despresurización y desfogue instaladas en las líneas de proceso. Las operaciones de aislamiento remoto mediante válvulas sólo se dan en los ingresos y salidas de cada sitio.

2.6.6 Medidas contra la Combustión

Todos los calentadores con llama están equipados con un doble sistema de bloqueo en el abastecimiento de gas. El sistema de encendido es mediante una secuencia automática.

2.7 Proyectos

No hay proyectos de expansión en consideración en ninguno de los tres locales, por lo menos en el futuro inmediato.

Debido a los resultados de la inyección del inhibidor de corrosión en las líneas de flujo en el campo, se está analizando la posibilidad de incrementar la capacidad de las bombas de aceite caliente para absorber el volumen extra de agua que se recibe en la planta de separación de gas.

2.8 Organización

Las operaciones y el mantenimiento de las plantas de gas están a cargo de Maple Gas que es encuentra bajo contrato. De la misma manera Duke Engineering and Services opera la planta de energía eléctrica y el sistema de transmisión, ambos contratos son abiertos. Maple Gas además opera la Refinería de Pucallpa.

Las tres plantas operan en dos turnos de 12 horas. En el caso de las dos plantas de gas el personal es residente por un periodo de dos semanas. Los dormitorios se encuentran dentro de las plantas pero lejos de las áreas de operaciones. Aproximadamente 20 personas trabajan en la planta eléctrica y 30 en las de gas.

2.9 Operaciones

2.9.1 Organización

Las operaciones y el mantenimiento están por completo a cargo de personal de nacionalidad peruana, la mayor parte de ellos cuenta con la experiencia de haber laborado en la industria de petróleo, en la empresa Petroperu. Un gerente extranjero estuvo a cargo de las operaciones de construcción y la puesta en marcha de la planta durante el primer año de operación.

La Gerencia operaciones y el mantenimiento tienen como base operativa la ciudad de Pucallpa la cual está a cargo de las operaciones de gas, y ambos jefes de planta deben reportarse directamente con él.

La operación de la planta eléctrica y el sistema de transmisión se manejan directamente desde Aguaytia.

2.9.2 Experiencia y Entrenamiento

La mayor parte de los operadores ha tenido un proceso de entrenamiento superior a dos semanas en plantas de gas similares a éstas localizadas en la ciudad de Texas. Además de cinco meses en los cuales ABB Randall dio entrenamiento durante la puesta en marcha de las operaciones.

P&IDs. Versiones simplificadas del manual están distribuidas en las instalaciones.

2.10 Ingeniería

2.10.1 Organización

Un número limitado de personal y recursos para ingeniería, tienen su base en Lima y se encuentra concentrado principalmente en las operaciones de Generación y Transmisión de Electricidad.

2.10.2 Estándares de Ingeniería

La planta fue construida usando los estándares de la API y ASME VIII además de los requerimientos de la NFPA para lo que es sistemas de protección contra incendios. Hasta la fecha no se han desarrollado estándares propios de Aguaytía Energy.

2.10.3 Proceso de Análisis de Riesgos

Las plantas de gas fueron sometidas a un HazOp en el año 1997 el cual fue llevado a cabo por la firma Quest Consultants Inc de USA. De esa revisión surgieron 33 puntos de acción. Adicionalmente la Sea Crest Group of Charlottesville de USA, llevo a cabo un Estudio mayor de Riesgos cuando el proyecto se completo en el año como requerimiento de la Overseas Private Investment Corporation (OPIC).

2.10.4 <u>Gerencia a Cargo</u>

Todas las partes involucradas en un cambio o modificación son consultadas antes de tomar una decisión sin embargo no se cuenta con un procedimiento normal para el control de este tipo de actividades.

2.11 Mantenimiento

2.11.1 <u>Organización</u>

Los servicios de mantenimiento de ambas plantas de gas son provistos por Maple Gas desde sus talleres ubicados en la refinería de Pucallpa. Duke Engineering and Services (PIC) provée el personal de mantenimiento a la planta de generación eléctrica.

2.11.2 <u>Experiencia y Entrenamiento</u>

El entrenamiento del personal de la planta eléctrica fue brindado por el personal residente de ABB en la misma planta de Aguaytía. El entrenamiento cubrió las operaciones, el mantenimiento y la inspección del equipo.

El personal de la planta eléctrica ayudaba a los ingenieros de ABB durante los mantenimientos y las actividades de inspección.

2.11.3 Filosofía

La filosofía de mantenimiento se basa en mantenimiento preventivo y predictivo con una estricta aproximación a lo que el diseñador del equipo recomendó.

Las paradas generales de las plantas de Gas se deberán llevar a cabo en intervalos de cuatro o cinco años para que el servicio cumpla con las condiciones medio ambientales y los estándares requeridos.

2.11.4 Electricidad

El análisis del aceite de los transformadores es llevado a cabo por Shell de manera anual. Las tomas a tierra de los equipos son verificadas de manera semestral.

El sistema de transmisión ha sido dividido en tres partes para un mejor mantenimiento. Los equipos de mantenimiento de la línea de transmisión tienen como base de operaciones la subestación de Tingo María

2.11.5 Mecánica

Las actividades de mantenimiento de las turbinas están a cargo del personal de PIC, lo que incluye las inspecciones del Tipo A, B y C. En caso de ser necesario se podría recurrir a personal auxiliar por parte del constructor ABB. Aguaytia debe asegurarse que las partes se encuentren disponibles y en la localización por lo menos seis meses antes de una inspección mayor.

Tipo A y B incluyen las partes de gas caliente a las 8000 horas. El tipo C es un mayor overhaul y se lleva a cabo a las 24,000 EOH.

Las protecciones y controles contra sobre velocidad de las turbinas son probadas anualmente.

Con respecto a los compresores Ariel y los Caterpillar, hay agentes locales en Pucallpa que son los encargados de proveer de partes y dar el mantenimiento a los equipos. Los compresores Ariel tienen aproximadamente 19,000 horas en operación. Un total overhaul debe ser llevado a cabo cuando los motores Caterpillar alcancen las 25,000 horas mientras que en el caso de los compresores Ariel el overhaul se realizara recién al alcanzar las 40,000 horas en operación. Todos los equipos y sistemas parecen estar 100% operativos.

Los análisis de aceite (incluyendo evaluación metalográfica) es llevado a cabo por Shell con intervalos de 15 días. Reportes completos son producidos por las áreas que realizan la inspección. Además Shell provee el servicio de análisis de vibración a todos los equipos rotativos (Shell Predictive), cada cuatro meses incluyendo un reporte completo.

2.11.6 Instrumentación

Los instrumentos de procesos son evaluados durante las operaciones, sin embargo el sistema ESD sólo puede ser evaluado con el sistema desconectado. Por lo que para testear el sistema ESD hay que retirar de servicio todas las plantas. Debido a esto se espera que la planta tenga una para al año de 4 o 5 horas a fin de probar el sistema ESD. El sistema de protección catódica de la tubería es inspeccionado todos los meses.

2.11.7 Contratistas

Hay un limitado uso de contratistas debido a que todo el mantenimiento se encuentra a cargo y es provisto por Maple desde la refinería.

2.11.8 Documentación y Registros

Las historía detallada de cada máquina se encuentra en una base de datos es ACCESS, así como en el nuevo software de mantenimiento MP2 que se ha terminado de implementar recientemente. Las actividades de mantenimiento aparecen descritas de manera comprensible y se lleva un buen registro de las mismas.

2.11.9 Reservas de Partes

Hay reservas de piezas y partes en las tres locaciones. Sin embargo para las partes más grandes, tales como las cabezas de los compresores o equipos de gran tamaño son colocados en los almacenes de Maple en la Refinería. Sólo partes manufacturadas por el constructor original son utilizadas.

Se estima los valores de los almacenes de Pucallpa y Zorillos en US$900,000 y US$ 700,000 respectivamente.
Un nuevo almacén ha sido construido en Tingo María para almacenar equipos y partes de la línea de transmisión.

2.12 Inspección

No hay un departamento dedicado solamente a inspección. El personal de mantenimiento se encarga de la realización de las inspecciones según lo recomendado por los consultores y han sido entrenados en las mismas instalaciones.

El grosor de las tuberías y los recipientes es probado cada 15 días en los 40 puntos de inspección identificados como críticos en la planta de gas usando un medidor Krautkramer DME. Una vez capturada la información esta es ingresada de manera manual en un cuadro que permite capturar el índice de corrosión en cada punto. Hay que tomar en cuenta que no se realiza ningún tipo de inspección en la planta de fraccionamiento. Sin embargo se lleva a cabo inspecciones a equipos aislados como los calentadores de aceite, el intercambiador de calor y algunos recipientes.

No se han encontrado evidencias de corrosión en la planta de fraccionamiento.

Se ha utilizado un Tuboscope para verificar la integridad de la línea desde la planta de gas hasta la planta eléctrica, no se encontraron evidencias de corrosión. Sin embargo se instalaran puntos de monitoreo tanto en la línea de 10 "como en la de 12"día.

La planta está equipada con una sola válvula de alivio, la cual es probada de manera constante in situ, usando gas del proceso para verificar su funcionalidad. Sin embargo, para facilitar este proceso deberían instalarse válvulas de alivio adicionales equipadas con su respectiva válvula de bloqueo. Un registro de los set points de todas las válvulas de escape debería ser llevado junto con los resultados de los tests.

2.13 Seguridad

2.13.1 Organización

El personal de Maple Gas provee los servicios de seguridad industrial para el proyecto completo incluyendo la planta eléctrica. El gerente de Seguridad reporta directamente sus operaciones con el director.

2.13.2 Performance

Las estadísticas de accidentes del proyecto no son muy buenas debido al los siniestros sufridos durante el año 2002, el cual costo alrededor de seis millones de dólares y un buen numero de horas fuera de servicio de una de las turbinas.

2.13.3 Comités

De manera mensual se llevan a cabo comités de seguridad, además de realzarse varias auditorías. Reportes detallados son preparados a fin de llevar a cabo las mejoras resultantes de las auditorías y comités.

2.13.4 Inspecciones y Auditorías

Se lleva a cabo de manera mensual e incluye un checklist. Un programa detallado de manejo de seguridad es planteado cada año e incluye las actividades como auditorías, entrenamientos (permisos de trabajo, aislamiento de equipos, investigación de accidentes, protección contra incendio), y revisiones de los planes de emergencia.

2.13.5 Control de las Fuentes de Ignición

Sellos y bridas colocadas en cada trabajo en las tuberías, además de una clasificación de los equipos eléctricos según su nivel de riesgo, nos permite considerar el manejo de ambos riesgos como excelentes.

Pruebas de presencia de gas inflamable son llevadas a cabo de manera común como parte del procedimiento de los permisos de trabajo.

2.13.6 Orden y Limpieza

En todas las instalaciones el orden y la limpieza son excelentes y los equipos se encuentran bien pintados.

2.14 Respuesta a Emergencias

2.14.1 Organización

Todo el personal de operaciones y mantenimiento ha sido entrenado y es capaz de operara los equipos de protección contra incendios.

2.14.2 Experiencia y Entrenamiento

El entrenamiento regular es realizado en las instalaciones de Maple en la refinería donde además se cuenta con una brigada contra incendios.

2.14.3 Ayuda Externa

Esta ayuda esta limitada a las instalaciones de la planta de fraccionamiento en Pucallpa y estaría brindada tanto por los bomberos de la refinería como los bomberos voluntarios de la ciudad de Pucallpa. No hay bomberos voluntarios en Aguaytía.

2.14.4 Planes de Emergencia

Planes de emergencia detallados se encuentran disponibles en todas las instalaciones y pueden ser encontrados en todos los centros de control. En la planta de fraccionamiento el plan también cubre escenarios especiales para los que se plantean diferentes tácticas de respuesta.

2.14.5 Simulaciones

Mensualmente se realizan prácticas con extiguidores. La brigada pública de Pucallpa y los bomberos de la refinería de Maple participan de los ejercicios conjuntos en la planta de fraccionamiento.

2.15 Vigilancia

2.15.1 Organización

La vigilancia de las operaciones de gas es brindada por Maple Gas, en el caso de la planta eléctrica es directamente por proveedores de seguridad. El personal de seguridad participa de manera activa en los ejercicios y simulacros en todas las instalaciones.

2.15.2 Medidas Preventivas

Todas las instalaciones están rodeadas por cercas y guardias durante las 24 horas del día en todos los accesos. Se ejerce un estricto control sobre todos los visitantes al momento de ingresar y retirarse.

Una base de la marina se localiza en Zorillos cerca de la planta de separación de gas y hay otra en Aguaytía. Sin embargo hay que anotar que la marina viene reduciendo la cantidad de personal en la zona.

CAPITULO III

EXPOSICIONES A RIESGO

3.1 Antecedentes

Aguaytia Energy, dueño del proyecto, es una compañía creada para financiar, construir y operar el proyecto. Esta entidad privada es subsidiaria de:

- The Maple Gas Corporation
- Pan Energy International Development Corporation (Acquired por Duke Energy)
- El Paso Energy International Company
- Ilinova Generating Company
- Scudder Latín American Power Fund
- Power Markets Development Company

La construcción comenzó en Agosto de 1996 bajo la modalidad de 3 contratos EPC llevados acabo por ABB y sus subsidiarias (LGA, ASESA). La operación comercial empezó en Julio de 1998.

Este proyecto es el primero en explotación de gas natural en el Perú, para el cual Aguaytia Energy tiene la concesión durante los próximos 40 años. Hasta el momento se han encontrado reservas de gas natural con un tiempo de explotación estimado en 22 a 25 años.

3.2 Ubicación

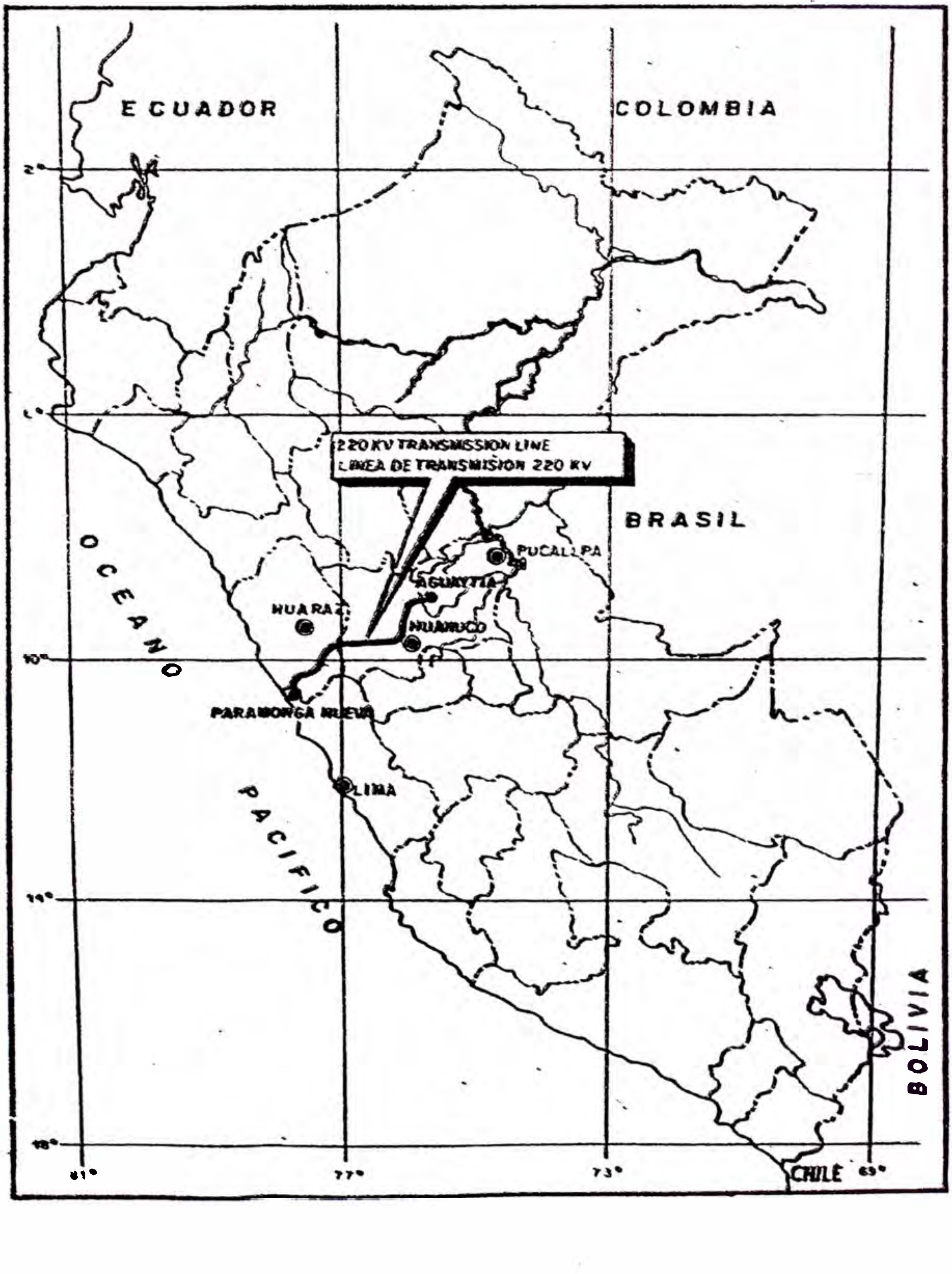
EL campo de Gas/Condensado de Aguaytia está situado en la rivera del rió Aguaytia en el departamento de Ucayalí con las coordenadas 75^0 12´W, 08^0 24´S, aproximadamente a 75 kilómetros al oeste de Pucallpa, 77 kilómetros nor-este de Aguaytia y 475 kilómetros Nor-Este de Lima. El área es en general tropical con lluvias forestales.

Allí se ubica una estación de medición y despacho de gas hacia Neshuya, unos 38 kilómetros Sur-Este de la planta de separación de gas. Donde el gas se divide, una parte es enviada a Pucallpa, 56 kilómetros al Nor-Este para alimentar la planta de fraccionamiento con gas, y otra es dirigida hacia Aguaytia 85 Km. al Sur-Oeste para alimentar la planta de energía eléctrica. La elevación del terreno es en general entre los 250 y los 300 metros por encima del nivel del mar y la temperatura fluctúa entre los 15°C y 38°C.

La línea única de transmisión de 220 kV cruza los Andes vía la subestación de Tingo Maria en 76^0 00´W 9^0 17´S y finaliza en la subestación de Paramonga Nueva subestación ubicada en la costa del Pacifico con coordenadas77^0 49´W 10^0 40´S.

La línea atraviesa cuatro diferentes zonas climáticas, jungla, montaña, puna y costa con una variación de altitud de hasta 4700 metros.

El siguiente mapa indica la localización de los lugares clave y la ruta seguida por la línea de transmisión.


ECUADOR
COLOMBIA
BRASIL
220 KV TRANSMISSION LINE
LINEA DE TRANSMISION 220 KV
PUCALLPA
AGUAYTIA
HUARAZ
HUANUCO
PARAMONGA NUEVA
LIMA
OCEANO
PACIFICO
BOLIVIA
CHILE
2°
6°
10°
14°
18°
81°
77°
73°
69°

3.3 Exposición

3.3.1 Fuego y Explosión

La exposición del proyecto al fuego, explosión, rotura de maquinaria e interrupción de negocios serán vistas en el capitulo Estimados de Pérdidas.

3.3.2 Rotura de Maquinaria

Las claves en rotura de maquinaría se encuentra ubicada en la planta de separación de gas (compresores de gas) y en la planta de generación de energía (turbinas-generador a gas). Ambos riesgo serán revisados en profundidad en el capitulo de Estimados de Pérdidas.

3.3.3 Subsuelo

Las tres operaciones se desarrollan en suelo arcilloso, ésta región del país no se caracteriza por tener movimientos de tierra y no hay áreas rocosas presentes. A pesar de esto todos los equipos y estructuras poseen un sólido cimiento en concreto incluyendo las columnas de destilación en la planta de separación y en la de fraccionamiento. Ninguna de las tres locaciones esta expuesta a deslizamientos de tierras y se encuentran separadas del terreno alto.

Las líneas de transmisión cruzan los Andes a través de diferentes tipos de terreno, y se ha tomado como medida de precaución el adecuar cada una de las Torres de transmisión a las particularidades de cada suelo. Para mayor información una torre a sido reubicada (No. 9) debido a lo débil que resultó el suelo en las inmediaciones del río Aguaytía. Otras dos torres (No. 66 and 99) van a ser reubicadas debido a que en los pasados dos meses sus cimientos se han ido erosionando rápidamente.

Todas las carreteras de acceso (excepto el tramo final hacia Pucallpa) están sin pavimentar y esta sometidas a un fuerte daño durante la temporada de lluvias que suele ser entre Noviembre y Abril. El acceso por los Andes está limitado por una sola carretera, la cual está en buenas condiciones y pavimentada, desde Tingo Maria hasta la costa.

3.3.4 Exposiciones a Fenómenos Naturales

Todas las instalaciones están alejadas de los centros poblados o de otras industrías en zonas verdes. Las tuberías se encuentran enterradas por completo.

3.3.5 Rayo

Las locaciones se encuentran expuestas a tormentas eléctricas en un promedio de 100 días por año. Todos los equipos cuentan con una adecuada puesta a tierra y se cuenta con una malla subterránea en todas las instalaciones. Las líneas de transmisión están equipadas con escudos protectores contra los impactos por rayo.

3.3.6 Terremoto

Las operaciones de gas y la planta de energía eléctrica se encuentran en un área clasificada como Zona 3 por Munchener Ruck, con un sismo de escala VIII en Mercalli Modificada con una probabilidad del 20% en 50 años equivalente a un periodo de 250 años. La línea de transmisión ingresa a una Zona 4 (Mercalli IX) en el extremo oeste cercano a la costa del Pacífico en Paramonga.

Las estructuras de soporte de los equipos están diseñadas para soportar un terremoto mayor al estimado y los equipos de proceso están reforzados más de lo normal.

3.3.7 Tsunami

No hay exposición a este tipo de riesgo.

3.3.8 Terrorismo

Con la captura de los 2 principales líderes terroristas en el año 1992, este riesgo ha disminuido a proporciones en que se puede considerar como despreciable. Los últimos incidentes ocurrieron en el año 1994 y desde ahí no se ha mostrado mayor actividad en la zona. Esto se refleja en el hecho que el gobierno ha reducido los contingentes de la Marina en la zona, ya que se considera al terrorismo como erradicado.

Los tres locales cuentan con personal de vigilancia permanente y disponible durante las 24 horas del día.

3.3.9 Inundación, Tormenta

La jungla tropical, sufre de tormentas con un promedio de 1000 a 1500 Mm. /año. Las instalaciones están ubicadas en terreno alto, tomando ventaja de la naturaleza y adicionando un sistema de control de lluvias mediante canaletas de desfogue.

Se han tomado medidas especiales para que toda el agua de lluvia sea llevada hacia el sistema de drenaje. Ninguno de los sitios cuenta con drenaje en el subsuelo los cual evita una posible filtración, además el sistema no cuenta con bombas de apoyo por lo que el agua se evacúa sólo de manera natural.

Todas las tuberías que cruzan ríos han sido realizadas mediante el método de "directionally drilled" (excavado diseccionado) y las tuberías están enterradas a una profundidad de 1.5 metros. Esto minimiza la exposición a riesgos. Durante la estación de lluvias los caminos de acceso sufren daños de manera constante debido a la falta de mantenimiento.

3.3.10 Caída de Aeronave

El único sitio que tiene exposición a este tipo de riesgo es la planta de fraccionamiento, la cual se encuentra a 4 Km de aeropuerto de Pucallpa.

3.3.11 Impacto de Buque

Exposición limitada debido a que el barco de LPG y la plataforma de carga y descarga nunca han sido usadas.

3.3.12 Choque en Carretera

Los camiones transportadores de LPG son cargados en la planta de fraccionamiento. La exposición potencial a impacto de vehículos contra las instalaciones es limitada. No se permite el ingreso de vehículos no autorizados.

3.4 Historial de Pérdidas.

El riesgo sufrió la rotura de un álabe, en la turbina de la planta generadora en el año 2002 con una pérdida combinada de daños a la propiedad e interrupción de negocios por un valor de US$ 6`000,000.

CAPITULO IV

VALORES ASEGURADOS

4.1 Propiedades

Los valores presentes han sido brindados por Aguaytía Energy. Estos valores serán utilizados en nuestros estimados de pérdida, sin embargo hay que aclarar que los valores no han sido verificados.

Declaración de valores (en US$) al 20 de Julio 2000:

Planta de Energía -Aguaytía	80,000,000
Sistema de Transmisión	79,325,000
Planta de Gas - Zorillos	31,185,000
Tuberías de Gas & NGL	38,390,000
Planta de Fraccionamiento - Pucallpa	19,155,000
Local de Transferencia deLPG - Manantay	2,620,000
Caminos y Equipos de Perforación	17,800,000
Máquinas y Equipos	225,000

Vehículos	125,000
Equipos electrónicos y de comunicación	890,000
Maple Gas	12,353,000
Total	**282,068,000**

Los escenarios que se han considerado para el PME de Daños a la Propiedad y Rotura de Maquinaría están considerados para el próximo periodo de aseguramiento iniciándose el 20 de Julio del 2004.

Los cálculos del PME están basados sobre el 100% de los valores asegurados suministrados por el cliente y reflejan el reemplazo a valor nuevo de las existencias bajo la cobertura.

4.2 Interrupción de Negocios

El calculo del PME de Interrupción de Negocios esta basado en la producción del periodo anterior, pero adecuándolo a los precios actuales del mercado y deberían reajustarse en caso de sufrir una pérdida.

El valor declarado por Aguaytí Energy es US$ 30 millones y Maple Gas US$ 10 millones haciendo un total de US$ 40,000,000 para 12 meses basado en las expectativas del negocio para el período 2000/2001. Con un período de indemnización de 15 meses.

CAPITULO V

ESTIMADOS DE PÉRDIDAS

Se deja en claro que este estimado de pérdidas es solamente una guía de referencia para el suscriptor, y que en ningún momento intenta cubrir todas las posibles eventualidades.

5.1 Definición de Pérdida

Para propósitos del seguro, la definición de pérdida es la siguiente:

5.1.1 Pérdida Máxima Estimada (PME)

La pérdida máxima estimada (PME) es definida como: "la pérdida que puede ocurrir en situaciones anormales en las cuales todos los sistemas de protección fallan y el incendio solo puede ser detenido por una barrera insalvable o por falta de material combustible"

5.2 Daños a la Propiedad PME

5.2.1 Explosión de Nube de Vapor (VCE)

En nuestra opinión se trata de un riesgo con una probabilidad bastante remota, la explosión de una nube de vapor tanto en la planta de separación de gas como en la de fraccionamiento. Sin embargo el historial de pérdidas ha demostrado que las plantas de procesamiento de gas son lugares de alto riesgo en lo que respecta a una explosión potencial.

Una explosión de nube de Vapor (VCE) puede resultar de la ignición de una nube de vapor generada por la rápida liberación de un líquido inflamable que se vaporiza o de una fuente de gas a alta presión. Daños producto de sobre presión, con la subsiguiente rotura de los equipos de proceso, pueden ser el resultado directo de grandes llamas a velocidad generadas por el proceso de deflagración como resultado de una nube de vapor atrapada en las estructuras de la planta.

Una potencial pérdida catastrófica existe cuando se tiene una gran acumulación de los siguientes tres tipos de material inflamable almacenados en la cercanía o en la misma área de procesamiento:

Tipo 1 Gases inflamables comprimidos y vapores cercanos a su presión crítica. La presión es lo suficientemente alta como para producir una nube de vapor que se confine dentro de la estructura de procesamiento.

Tipo 2 Gases inflamables de Hidrocarburos a presión en estado líquido.

Tipo 3 Líquido inflamable con un punto de ebullición superior a los 20°C y un flash point inferior a 40°C cuando se presenta en estado líquido con una presión cercana a su punto de ebullición a presión atmosférica.

5.2.2 Reconocimiento

Los equipos de procesamiento en ambas locaciones han sido construídos mediante la utilización de módulos, con un mínimo nivel de congestión o confinamiento presente. Pero aun así una fuga mayor resultaría en un "flash fire" con un mínimo de equipo dañado debido a la sobre presión generada.

Gracias a la buena separación existente entre el compresor y el de-etanizador en la sección de separación de gas (proceso con en el que se encuentra el mayor valor), el daño podría considerarse como mínimo para este tipo de eventos como se demuestra más adelante.

5.2.3 Selección de las Fuentes

La selección de las fuentes se basa en el siguiente criterio:

- La localización de la fuente en o cerca de de áreas de proceso de gran valor y con gran concentración de bienes en donde se reúnen las condiciones necesarias como para que se forme una nube de vapor.
- Almacenes o tanques donde se tenga material inflamable en suficiente cantidad que pueda generar una pérdida catastrófica.
- La localización de las áreas cerca de un área del proceso donde se pueda causar una potencial interrupción del negocio con elevadas pérdidas.

La siguiente lista muestra los lugares en donde se podrían generan los más significativos VCE escenarios.

No	Description	Type	Components		Temp	Type 1		Type 2/3		Cloud		
			Name	Wt %	°C	P(barg)	d (mm)	V (m³)	I (t)	M (t)	r (m)	Drift (m
1	De-ethaniser	2	Propane	100	37			5	3	1	21	36
2	Cold Separator	2	Butane	50	-28			1	1	0	6	1
			Propane	50								

Ambos almacenes contienen la suficiente cantidad de material volátil como para producir un VCE. Después de las consideraciones con respecto a la densidad, el nivel de congestionamiento y confinamiento asociado con las estructuras de proceso y una potencial nube de vapor de gran tamaño, se ha seleccionado un caso para la evaluación:

El caso seleccionado es una gran pérdida en propiedad a causa de la daño en el 16-0603 de-etanizador.

5.2.4 Cuantificación y Estimación de Zonas Dañadas

Nuestra aproximación refleja fundamentalmente los últimos avances en la estimación de pérdidas en este tipo de eventos, y se basa en un modelo utilizado por los mayores reaseguradores en los últimos años. El método implica la inicial cuantificación del tamaño de la nube de gas y su dispersión, seguido de las condiciones de la planta y cuan rápido se propagaría una llama con el consecuente daño por sobre presión.

Las siguientes son las categorías de congestionamiento y confinamiento en las estructuras de la planta, las cuales tienen directa relación con la magnitud del VCE:

Severo

Moderado

Bajo

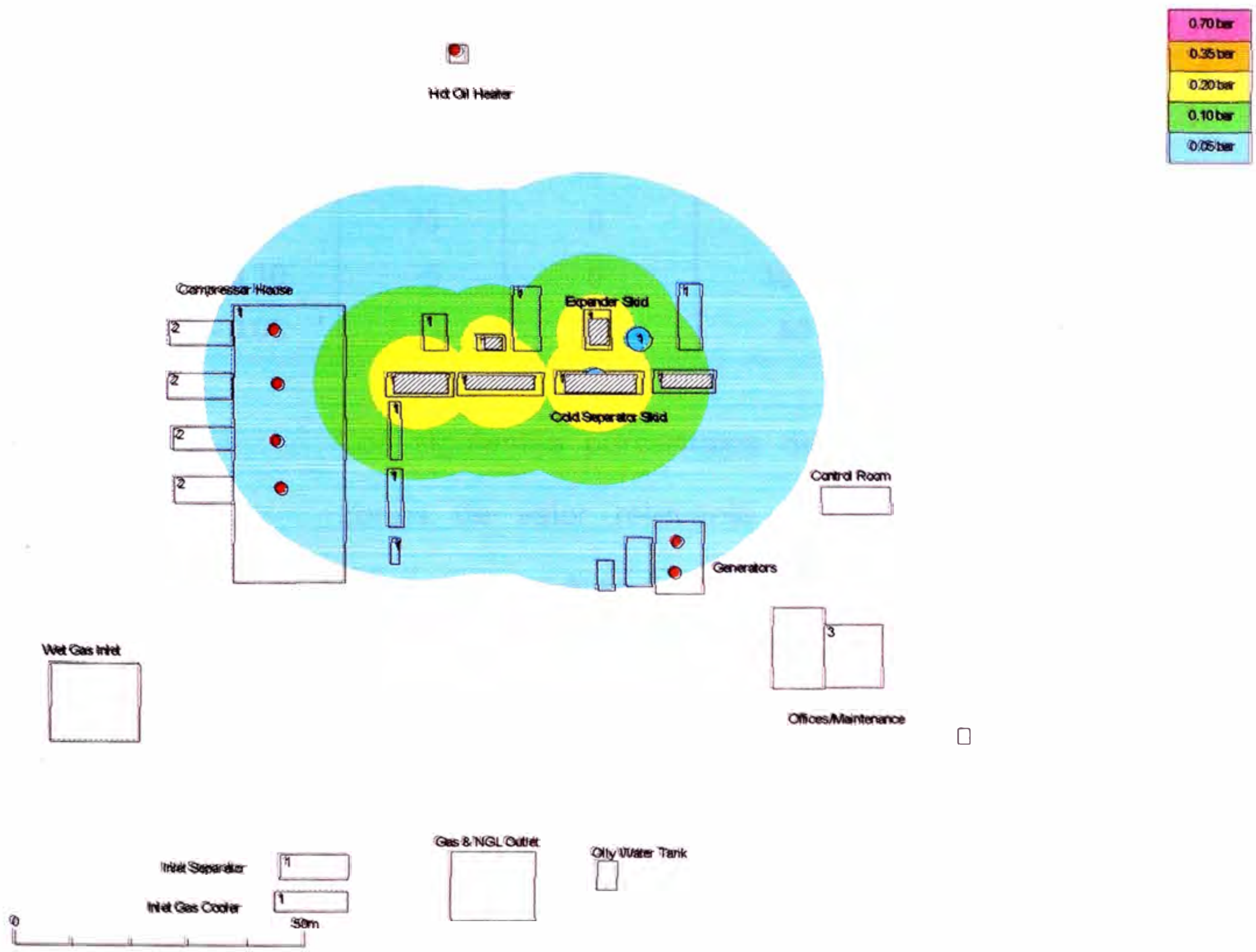
Mínimo

5.2.5 Planta de Separación de Gas

Potenciales "flash" en la zona de almacenamiento o de proceso tales como la parte baja del de-etanizador, seguido de la ruptura de la tubería y formación de una nube de.

Grado de confinamiento y congestión: Mínimo/Bajo

Los círculos de sobre presión muestran las áreas que se verían afectadas en caso de una explosión en alguna de las estructuras centrales.



5.2.6 <u>Asignación de Valores a la Propiedad y Estimado de Pérdidas</u>

Consideraremos el daño principal como una explosión inicial y una onda de choque que parta desde los equipos de proceso o sea producto de la ruptura de una tubería:

Localización del Daño por Fuego y Explosión (%)					
Anillo de Sobre presión	**Planta de Proceso**	**Maquinaria Pesada**	**Torres de Enfriamiento**	**Tanques**	**Distancia del Lugar**
> 0.70	100	80	100	100	100
0.70 – 0.35	80	40	100	100	80
0.35 – 0.20	20	0	100	100	20
0.20 – 0.10	5	0	100	50	5
0.10 – 0.05	0	0	50	0	0

Los siguientes porcentajes de daños están aplicados a las zonas de valor relevante en las plantas, basados en el porcentaje del área de cada planta que es cubierto por la zona de sobre presión.

La pérdida máxima por VCE se puede estimar en menos de US$ 3 millones ya que la onda de sobre presión generada no excede los 0.2 Bar, lo cual causa grandes llamaradas de fuego, pero no un sensible daño por la onda de choque.

5.2.7 Jet Fire

El sitio con mayor exposición a “jet fire” es la planta de separación de gas donde la alta presión (2500 psig) de llegada del gas húmedo está localizado a 30 metros de la contracción donde se ubican los compresores.

En el caso de una ruptura en la entrada de gas, resultaría en un “jet fire” que destruiría aproximadamente el 50% de las instalaciones. Una situación similar podría darse en la tubería principal de 12” de gas residual en la estación de Neshuya la cual opera a 1050 psig, por cuya ruptura la presión bajaría rápidamente.

La pérdida máxima estimada por “Jet fire” es: US$ 15 millones.

5.2.8 Spill Fire

La mayor exposición a un “Spill fire” está en el área donde se encuentra el calentador de aceite. En éste proceso el sistema de calentamiento opera cerca de su flash point, y por cualquier falla rápidamente se puede incendiar, lo cual envolvería en un mayor fuego todas las áreas aledañas a este sector de la planta.

Debido a la buena distribución de la planta solo el de-etanizador y el enfriador de la planta de separación de gas se verían afectados, esto representa el 40% del valor asegurado de esa área.

El daño en la planta de fraccionamiento seria considerablemente inferior. La máxima pérdida estimada para un “Spill FIRE” es: US$ 13 millones.

5.2.9 Incendio en Turbina

Un fuego incontrolable en una de las turbinas de gas, puede resultar en una perdida de US$ 15 millones en daños en caso que los sistemas de supresión fallen. Esto es un daño en un 80% en la sección de la turbina/compresor.

5.2.10 Incendio en Taques

El almacenamiento consiste en tanques pequeños de 100 bbl localizados en el interior de la planta de fraccionamiento en un área aislada. Exposición mínima.

5.2.11 Peligros Naturales

El mayor peligro natural es un terremoto. Sin embargo debido al tipo de construcción modular, el daño potencial no seria superior a los peligros anteriormente evaluados.

La separación existente entre las tres diferentes locaciones del proyecto evita la acumulación de bienes. Entonces la pérdida máxima para Peligros Naturales seria de: US$ 15 millones.

5.2.12 Conclusión

Basados en el peor de los casos de "Jet Fire" o un incendio en una turbina.

Se propone el siguiente modelo basado en 27 meses incluyendo inflación:

- Para un evento que ocurra en el siguiente periodo asegurado.
- 15 de periodo de reconstrucción.
- Basado en los valores del 20 de Julio 2000.

Asumiendo una inflación anual del 3%.

Además de agregar un 14.5% de gastos debido a la extinción del incendio, remoción de escombros y gastos adicionales se sugiere el siguiente estimado de perdida.

El PME por daño a la propiedad se puede estimar en: US$ 18 millones.

5.3 PME para Rotura de Maquinaria

Este riesgo esta asociado con

- El costo del reemplazo de grandes partes debido a la rotura.
- El costo de la reparación de la maquinaria y equipos.

En general para una falla de este tipo se considera al suceso como algo no previsto o inevitable, que no ocurriría de manera normal. El desgaste o fatiga de los equipos en su tiempo de vida normal no esta incluído.

Un incidente de este tipo puede ser el resultado de:

* Defectos de material, diseño, construcción, montaje o ensamblado.
* Accidente fortuito de trabajo tales como vibración, mal ajuste, pérdida de partes o inefectiva o mala lubricación, golpe de ariete o sobre calentamiento local.
* Excesiva o baja intensidad de corriente, falla de sellos, corto circuito, apertura de circuitos o arco eléctrico, además de efectos de la estática.

Para la mayor parte de procesos productivos, el daño consecuencial de la interrupción de la producción es mayor que el costo del reemplazo o la reparación de los equipos.

Para ruptura de maquinaría, se evalúa la exposición catastrófica (PME) que pueda causar mayor daño a los equipos y/o la producción. Para aclarar el concepto, es necesario dar una mirada a los equipos de planta usados en este proyecto, los cuales podrían sufrir un accidente inesperado. En particular, podríamos ver las máquinas y equipos con mayor exposición a riesgo y combinarlo con las que tienen un mayor valor y complejidad en cuanto a emplazamiento o riesgo operacional.

El riesgo se puede medir en velocidad (para el caso de máquinas rotativas), presión, temperatura y ambiente corrosivo (para los demás equipos).

5.3.1 Máquinas Rotativas de Alto Riesgo

Las máquinas rotativas de altas velocidades tales como turbinas, compresores, reductores de velocidad, alternadores son mas propensas a sufrir daños accidentales durante la operación, debido a problemas de lubricación, fallas en los alabes, vibración o fallas en los acoples. Usualmente es posible de reparar la falla en caso se cuente con las partes de reemplazo y la mano de obra capacitada en 1 ó 2 meses.

Daños en equipos rotativos resultados de sobre velocidad, excesiva vibración o fallas en la fabricación, pueden requerir del reemplazo del casco exterior. Se considera a estos escenarios como de muy baja probabilidad, porque se cuenta con sofisticada instrumentación tanto para la detección y protección de los equipos contra la sobre velocidad y vibración en las turbinas de gas en Aguaytia. En último caso estos eventos catastróficos pueden ocurrir y sus daños deben de ser evaluados. No se cuenta con casco o rotor de reemplazo para las unidades turbogeneradores. Se cuenta con un pistón y cilindro ensamblado y almacenado para remplazar un compresor reciprocante Ariel incluyendo sus sellos y anillos.

No hay posibilidades de rebobinar un motor en el sitio este tendría que ser enviado hasta la ciudad de Lima. El más grande de los motores es de 40HP. Los estatores de los turbo generadores marca ABB tienen que ser enviados a Lima para su reparación.

Los turbo generadores son monitoreados por un ABB Egatrol 300 el cual incluye detección de vibración y desplazamiento con alarmas y parada automática.

5.3.2 Máquinas Rotativas de Bajo Riesgo

Las máquinas rotativas que operan a bajas velocidades son relativamente pequeñas en cuanto a potencia y no poseen mayor exposición a riesgo o valor que las máquinas de altas velocidades descritas previamente.

La planta cuenta con un considerable número de bombas, compresoras y otros equipos, los cuales pueden ser incluidos dentro de esta categoría.

5.3.3 Equipos Fijos – Activos de Gran Valor

Los equipos fijos como las torres, intercambiadores, equipos a presión, reactores y tanques todos están diseñados según códigos establecidos (ASME VIII and National Board Certified) y la probabilidad de falla es baja Problemas específicos en este tipo de plantas están relacionados a fallas internas, corrosión o colapso de metal por fatiga. A pesar de la gran cantidad de equipos la probabilidad de falla es baja, y el daño potencial puede ascender a US$ 1 millón y el tiempo de fabricación puede considerarse de-etanizador o la columna de fraccionamiento. El enfriador de aluminio puede incluirse en este tipo de recipientes.

El riesgo de desintegración del recipiente producto de una falla de materiales no puede ser despreciado pero debe considerarse como una falla con una posibilidad muy baja.

En adición a la falla de material debe considerarse, la sobre presión causada por una falla en una zona diferente como sería el caso de una válvula de cierre.

En general el proceso para llevar acabo la extracción de gas y el fraccionamiento del mismo es un proceso estándar bien conocido y operado en la industria a temperaturas y presiones moderadas. El uso de materiales exóticos esta limitado al acero inoxidable en la zona del enfriador del gas húmedo y el aluminio en el enfriado de la planta de gas.

El siguiente cuadro muestra el valor de algunos equipos críticos identificados.

5.3.4 Maquinaria Rotativa de Alto Riesgo

Unidad	Ítem	Valor Estimado (US$)	Comentarios
Separación de Gas	11-0601 A/B Compresor de Gas Residual	1.5	Caterpillar (1666 HP/1000 RPM gas engine driven reciprocating Ariel compressor
Separación de Gas	11-0602 A/B Compresor de Gas para Reinjeccion	2.0	Caterpillar (2250 HP/1000 RPM gas engine driven two stage reciprocating Ariel compressor
Separación de Gas	28-9601 A/B Generador	1.0	Waukesha 500 kW 1800 RPM @ 460 V
Separación de Gas	13-0601 Expansor/Compresor	2.0	Rotoflow centrifugal 835/809 HP 40,000 RPM
Planta Eléctrica	Gas Turbina Generador A/B	18.0	Model ABB GT-11 NM 78 MW @ 13.8 kV

5.3.5 Calentadores

Unidad	Ítem	Valor Estimado (US$)	Comentarios
Planta Eléctrica	Calentador de Gas	-	Direct fired gas
Gas Separación	14-9501 Calentador de Aceite	-	Heat Recovery Corp. Direct fired gas.
Fraccionamiento	14-9511 Calentador de Aceite	-	Heat Recovery Corp. Direct fired gas

5.3.6 Equipos Fijos

Unidad	Ítem	Valor Estimado (US$)	Comentarios
Separación de Gas	15-0601/2 Aluminium Enfriador	1.0	ALTEC
Planta Eléctrica	Generador Transformador	3.0	ABB 13.8/220 kV 100 MVA

5.3.7 Conclusiones

Una significativa interrupción del negocio puede ocurrir en caso de una pérdida de una de las turbinas a gas en la planta de energía eléctrica, a consecuencia de un incidente de sobre velocidad y produciendo una falla catastrófica la cual puede ascender a 15 meses de paralización de la unidad.

Basado en la información brindada se sugiere que el PME para rotura de maquinaria debe ser estimado en: US$ 18 millones.

5.4 PME de Interrupción de Negocios

En esta sección del reporte se analizara el riesgo potencial para la cobertura de interrupción de negocios, relacionado con los Daños a la Propiedad y con la Rotura de Maquinaria.

5.4.1 Parámetros para la Evaluación

Para analizar la cobertura de interrupción de negocios es necesario fijar los parámetros que han sido proyectados, en caso de requerir la reconstrucción de las unidades después de que un evento catastrófico.

El acceso de equipos pesados hacia las instalaciones debe ser realizado a través del río Amazonas y Ucayali hacia la ciudad de Pucallpa, ya que los accesos vía carretera desde el Pacifico cruzando los Andes no son adecuados para transportar carga pesada. Los Transportes en la ruta están limitados por la máxima capacidad de los puentes.

El equipo sólo puede ser llevado al sitio en la estación de lluvia (Noviembre a Abril) debido a que sólo en esos meses el nivel del río es lo suficientemente alto como para ser navegable. Por lo tanto sólo disponemos de 6 meses.

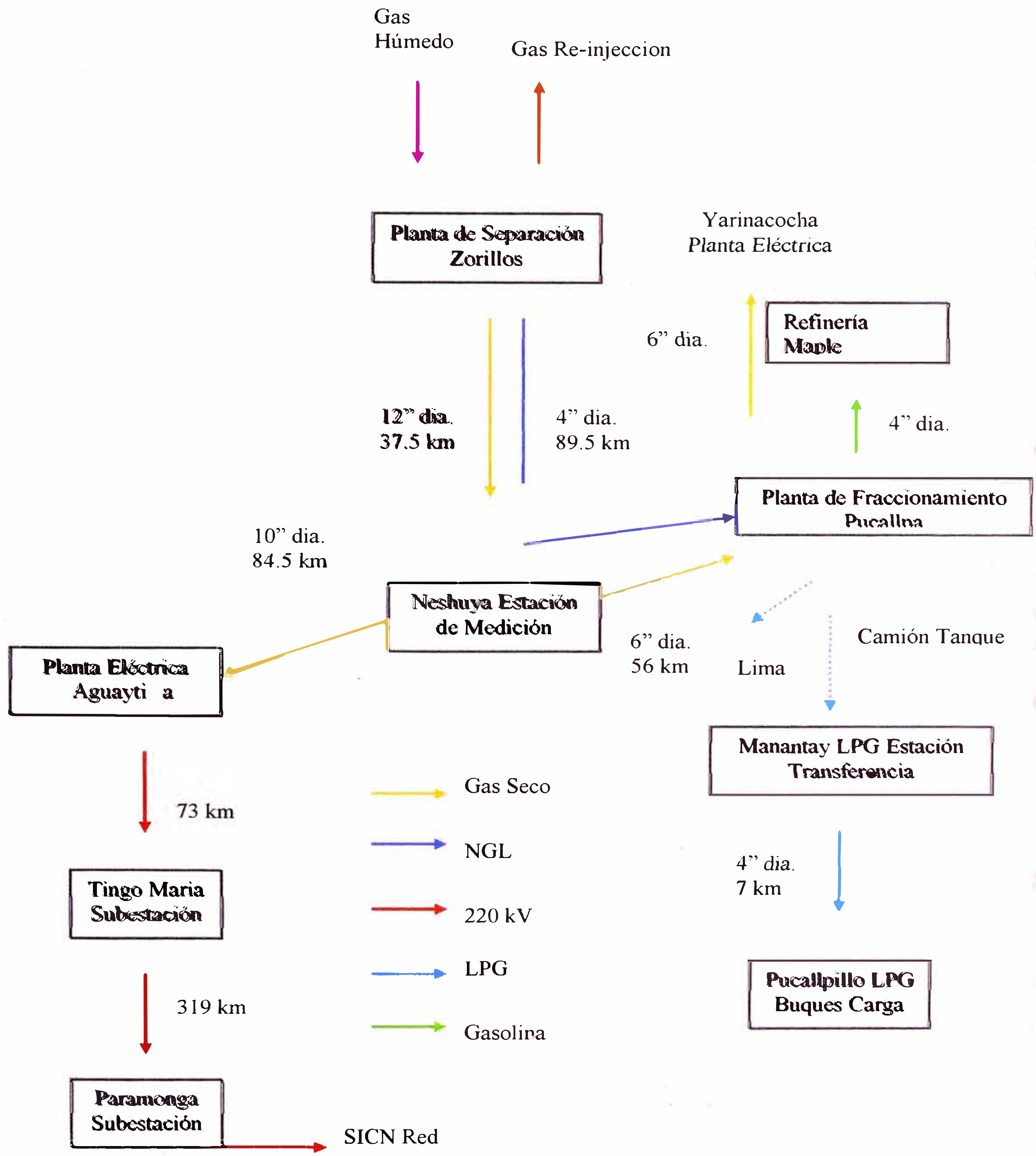
Con respecto a las turbinas de gas de ABB, el tiempo de reemplazo puede ser estimado en de 9 a 12 meses, lo cual incluye un mes de embarque. Asumiendo que no se contará con el clima adecuado el tiempo total de reemplazo sería de 18, lo cual es 3 meses en exceso con respecto al periodo de indemnización de 15.

Con respecto a la reciente compra de ABB por parte de Altrom el futuro de la turbina GTE 11 y su tiempo de despacho dependerá de la reestructuración interna de la compañía.

Un tiempo similar de reemplazo puede aplicarse al de etanizador y a la columna de fraccionamiento, después de un daño severo por incendio.

5.4.2 Interdependencias de Plantas

Para entender la interdependencia entre las plantas del proyecto el siguiente diagrama ilustra las interconexiones a través de tuberías.



El análisis de pérdidas considera las siguientes áreas:

5.4.3 Proveedores

El único stock de gas natural en la zona lo posee la misma Aguaytía Energy por lo que no se cuenta con la posibilidad de comprar gas natural para operar la planta. En cuanto a los 7 pozos operativos solo 4 son necesarios para mantener la planta eléctrica operando en horas pico, los otros tres están siendo utilizados para reinyectar el gas.

Por lo que la pérdida de un sólo pozo no afectaría la producción de la planta, en caso de ser necesario uno de los pozos de inyección puede ser rápidamente transformado en producción.

5.4.4 Clientes

Estos son los tres clientes principales:

- ***Refinería Maple:*** La refinería de Pucallpa consume toda la gasolina natural producida en la planta de fraccionamiento. Una perdida mayor en la refinería tendría como solución el envío de la gasolina hacia la costa del Pacífico a otra refinería peruana. Se debe aclarar que no se cuenta con stock de gasolina natural actualmente almacenada y que solo se ha destinado un tanque a este servicio.

En este caso sólo habría gastos de operación adicionales debido al transporte de gasolina hacia la costa del Pacífico.

- ***LPG Clientes:*** Hay un gran número de clientes de LPG en el área de la ciudad de Lima, que son diariamente abastecidos por 27 camiones LPG, que se cargan durante las noches. La pèrdida de uno de estos clientes en Lima no representaría una gran afectación para el negocio.
- ***Abastecimiento Eléctrico:*** La energía eléctrica es enviada vía el sistema de transmisión del proyecto Aguaytia y se conecta a través de la red peruana SICN con un sinnumero de clientes. La pérdida de uno de los clientes no afectaría las características del negocio, sin embargo la pérdida de la red si tendría una grave implicancia en la producción.

5.4.5 Logística

5.4.5.1 Caminos

El acceso a la planta de fraccionamiento es una de las claves a tomar en cuenta para la afectación por interrupción. El camino montañoso hacia la ciudad de Lima es el único método de exportación del LPG y se realiza por una sola carretera. Estas exportaciones dependen tanto del estado de los camiones de transporte como del camino y los puentes en sí.

La pérdida de uno de estos vehículos no afectaría el flujo de producción ya que se posee una gran flota (27) dedicadas a transportar LPG. Pero la inutilización o bloqueo de la ruta principal podría paralizar los envíos por hasta dos semanas, y la planta sólo cuenta con capacidad de almacenamiento para 5 días.

5.4.5.2 Tren

No hay Tren disponible.

5.4.5.3 Tuberías

La tubería que abastece la refinería de Maple en Pucallpa, presenta una exposición mínima.

La interdependencia entre la planta principal y la planta de fraccionamiento o energía eléctrica es por la tubería de NGL. Una falla en la tubería de NGL no afectaría la producción de NGL ya que el gas podría ser reinyectado.

Una falla en la tubería permitiría proseguir con la operación en la planta de fraccionamiento, sin embargo podría restringir el trabajo de la planta eléctrica, que por el momento sólo está siendo usada en horas pico.

El trazado de la tubería, sin embargo, es bastante claro y permite el tener acceso y facilidades al mismo en caso de mantenimiento o reparación.

5.4.5.4 Marina

La instalación portuaria para la exportación de LPG aun no ha sido usada.

5.4.6 Unidades de Proceso

Para calcular el PME por interrupción de negocios en un escenario catastrófico se ha evaluado las ventas de los 3 productos en los últimos años.

	Ventas	Ganancia Estimada
Electricidad	US$ 28.5 millones (50 %)	US$ 15 millones
LPG	US$ 13.5 millones (25 %)	US$ 7.5 millones
Gasolina Natural	US$ 14 millones (25 %)	US$ 7.5 millones

5.4.7 Planta de Separación de Gas

El PME para interrupción de negocios se encuentra dominado por la planta de producción de gas. Un incidente catastrófico en la planta de gas resultaría en una total paralización del proyecto por un periodo estimado en más de 15 meses. En caso de suceder la interrupción del negocio costaría un aproximado US$ 37.5 millones en este período, aun si la refinería de Maple siguiese operando utilizando crudo local. Claro que sufriría una recarga en su operación si se tuviese que importar el crudo desde alguna otra parte.

El contrato con la compañía de transporte, requiere el pago por parte de Aguaytía de US7,500 diarios estée o no estée el LPG disponible. Por lo tanto la compensación por una paralización de 450 días ascendería a US$ 3.4 millones.

Lo que nos daría una pérdida total de US$ 40.9 millones.

La planta había sido diseñada para separar el gas del campo y enviarlo directamente por una línea de gas residual sin separar los NGLs. Sin embargo debido a la gran cantidad de NGLs ha sido necesario llevar a cabo una serie de modificaciones en el ingreso a la planta eléctrica y en la estación de Neshuya. Adicionalmente la corrosión por CO_2 hace necesario una completa revisión del sistema de tuberías para asegurar que no se presente una posible falla que pueda dañar las turbinas.

5.4.8 Planta de Fraccionamiento

Un incidente catastrófico en esta localización paralizaría toda la producción de NGLs y el gas de la planta de separación tendría que ser reinyectado. Asumiendo que el grueso de las ganancias por LPG y gasolina natural ascienda al 50% del total y el periodo de interrupción del negocio llegue a los 15 meses, entonces se podría estimar la pérdida en US$ 18.8 millones. Esto es en caso que la refinería de Maple estuviese operando.

5.4.9 Planta Eléctrica

El único incidente catastrófico en esta planta seria un incendio en una de las unidades turbo generadoras, lo cual reduciría la producción de energía eléctrica al 50% por un período de 18 meses. Asumiendo que la ganancia es el 50% del total y que la paralización ascendería a más de 15 meses, la pérdida se podría estimar en un total de US$ 9.4 millones.

5.4.10 Maquinarias

Desde el punto de vista de rotura de maquinaría, el mayor riesgo se encuentra en el áreas del turbo expansor, el compresor reciproncante y los equipos de reinyección en la planta de separación de gas. La pérdida de uno de los turbo expansores provocaría que la planta solo opere al 30% de capacidad usando la válvula de expansión Joule Thompson , resultando en una pérdida estimada en US$ 9 millones en los 12 meses que tomaría el reemplazar la parte dañada.

La pérdida de uno de los compresores de gas causaría un descenso en la producción de esta un 50% ya que los dos compresores con los que se cuentan son necesarios para que se opere a máxima capacidad.

No hay maquinaria considerada para esta parte del informe en la planta de fraccionamiento.

En la planta eléctrica la ruptura de maquinaría ha analizar debe estar centrada en la pérdida de una de las dos turbinas a gas, lo cual daría como resultado una paralización de más de 15 meses y una pérdida de US$ 9.4 millones. Pérdida en el generador y el transformador incurriría en el mismo monto de pérdida, sin embargo estos equipos son de más fácil reemplazo.

5.4.11 Instalaciones de Almacenamiento

Las instalaciones de almacenamiento de LPG en la planta de fraccionamiento no están en uso. Estas consisten en 18 tanques de 227 m^3 presurizados cada uno de los cuales es utilizado para almacenar NGL para la planta. La pérdida de uno de estos tanques resultaría en la paralización de la planta de fraccionamiento, la pérdida resultaría en la restricción de la capacidad de almacenamiento en la planta de fraccionamiento. El periodo de reparación del tanque se estima en cuatro meses.

La pérdida podría estimarse en US$ 5 millones. La refinería de Maple no sufriría afectación sin embargo algunos componentes de su combustible de alto octanaje incrementarían su precio.

5.4.12 Servicios

5.4.12.1 *Vapor*

No hay instalaciones para generar vapor.

5.4.12.2 *Electricidad*

A pesar de que la planta de separación de gas es 100% redundante en cuanto a su capacidad de generación, la planta de fraccionamiento sin embargo es enteramente dependiente del servicio público. Hay que anotar que la estación de Yarinacocha está situada en la misma ciudad de Pucallpa. Por lo tanto la exposición a pérdida de electricidad a través del sistema es considerada como mínima. Además se debe considerar que se puede contar con equipos de generación móviles en caso de emergencia.

5.4.12.3 *Combustible*

El combustible en las tres estaciones es abastecido por la tubería de gas natural.

5.4.12.4 *Aire*

Se cuenta con un 100 % de redundancia en el sistema de compresión de aire en las tres locaciones.

5.4.12.5 *Agua*

Los requerimientos de agua no están limitados y son abastecidos directamente desde pozos de agua en las diferentes plantas.

5.4.12.6 *Llamaradas o Antorchas*

Todas las válvulas de descarga a la atmósfera están lo suficientemente elevadas como para compensar una falla en el sistema. Además se cuenta con un sistema de descarga de emergencia. A pesar de esto en caso de presentarse la acumulación de una nube de gas, la localización de la antorcha es tan remota y con tan buena ventilación que el gas seria dispersado sin presentar mayor riesgo. El pequeño tamaño de las antorchas permite su fácil reemplazo.

5.4.13 Otros

Las operaciones en las tres plantas pueden considerarse como limpias y sin riesgos para el ambiente.

5.4.14 Conclusiones

Basado en el análisis anterior las pérdidas deberían ser estimadas en:

PME Daños a la Propiedad	US$ 40.9 millón
PME Rotura de Maquinaria	US$ 9.4 millón

5.5 Resumen de Pérdidas

El siguiente cuadro es el Resumen de Pérdidas:

	Escenario	US$ millones			Comentario
		DP	IN	DP+IN	
PME Daños a la Propiedad	Sep. de Gas Planta Eléctrica	18 15	40.9 9.4	58.9 24.4	15 meses 15 meses
Rotura de Maquinaria (RM) PME	Planta Eléctrica	18	9.4	27.4	15 meses

CAPITULO VI:

PROTECCIÓN CONTRA INCENDIO

6.1 Equipos a Prueba de Explosión

Debido al tipo de construcción modular, no se cuenta con muros cortafuegos más que en lugares específicos. Sin embargo se debe dejar notar que los equipos están separados por distancia, de otras unidades de proceso. La excepción se da en la planta de fraccionamiento donde el soporte de enfriador fin fan cooler es de concreto, a pesar de no cubrir toda la altura del mismo. Este enfriador sí se encuentra cerca de las instalaciones de proceso.

Los transformadores en la planta de generación eléctrica, están separados del generador por un muro cortafuego completo, como se puede ver en la fotografía.

Fotografía #10 **Vista de Muro cortafuego**

6.2 Detección de Fuego y Gas

La detección de fuego y gas solamente está disponible en el interior de las turbinas de la planta eléctrica. Este sistema apaga automáticamente las turbinas. Un panel Spectronics está ubicado en el cuarto de control.

Todas las oficinas administrativas, cuartos de control y almacenes están equipados con detectores de humo. Además se cuenta con seis detectores de gas en la planta de separación.

6.3 Agua Contra Incendio

6.3.1 Planta de Separación de Gas - Zorillos

No hay sistema fijo de agua contra incendio instalado.

6.3.2 Planta de Fraccionamiento - Pucallpa

Debido a las grandes cantidades de LPG almacenado en el lugar la planta de fraccionamiento incluye un sistema de agua contra incendio. Este sistema cubre los recipientes de almacenamiento y el área de procesos en sí. Consta de una combinación de monitores e hidrantes.

El sistema tiene de 5000 barriles de capacidad dedicada de manera exclusiva almacenada en un solo tanque y cuenta con un sistema de bombeo de 1500 gpm que es manejado desde una bomba a motor diesel, marca Patterson la cual opera a 2100 rpm alimentando una tubería de 10" de diámetro con la que se abastece al anillo protector. Se alimenta un total de siete monitores.

La línea contra incendios se mantiene presurizada por medio de una bomba jockey y la bomba diesel arranca de manera automática ante una pérdida de presión en la línea.

Fotografía #11 **Una vista general de las instalaciones contra incendio.**

6.3.3 Estación de Transferencia de LPG - Manantay

Los cuatro recipientes a presión están protegidos por medio de dos monitores alimentados desde una bomba diesel de 500 gpm de capacidad. La línea de incendio principal se encuentra presurizada por medio de una bomba jockey y la bomba principal arranca en el momento que cae la presión en la tubería. El agua de reserva es un solo tanque de 100 barriles de capacidad.

Estas instalaciones no están siendo utilizadas.

6.3.4 Planta Eléctrica - Aguaytia

El sistema consiste en dos reservorios de agua dedicados que alimentan a dos bombas de 1250 U S gpm marca Peerless, una de las cuales es diesel. Estas a su vez alimentan un anillo protector equipado con hidrantes y monitores.

La capacidad de agua contra incendio está calculada en base a la activación de los dos sistemas contra incendio deluge de los transformadores de una de ellas además de la utilización de los hidrantes y monitores cercanos.

La línea contra incendio se mantiene presurizada por medio de una bomba jockey, y las bombas contra incendio arrancan de manera automática cuando se detecta pérdida de presión en la tubería.

Fotografía #12 **Una vista general de las bombas contra incendio se puede apreciar en la fotografía.**

6.4 Protecciones Especiales

6.4.1 Equipos de Proceso

Se cuenta con un sistema de protección fijo en base a CO_2 en las turbinas de gas en la planta eléctrica. Estos son activados por detectores UV/IR. Un solo detector da una alarma al cuarto de control, en caso de que se active otro el sistema se descarga y se apaga la turbina.

El equipamiento consiste en un solo recipiente de CO_2 que protege todas las instalaciones de la turbina. Ambas turbina cuentan con el mismo sistema y esta diseñado para dar descargas independientes.

Un sistema de sprinklers automáticos deluge está instalado sobre el generador y los transformadores. Estos se activan directamente mediante detectores de calor. En los transformadores están ubicados encima de los recipientes de aceite.

6.5 Equipos Móviles

6.5.1 Vehículo Contra Incendio

Un solo vehículo contra incendio, American La France 1975 está disponible en la refinería de Maple en Pucallpa. Esta equipado con una bomba de 1000 US gpm, y cuenta con una reserva de 500 galones de agua y 500 galones de Espuma. No hay otro vehículo en las instalaciones.

6.5.2 Extintores

Todas las locaciones están equipadas con extintores manuales. Además se cuenta con equipos rodantes de 50 kilogramos de polvo químico seco, localizados en puntos estratégicos.

6.6 Pruebas

Los extintores cuentan con un registro en el cual se lleva la información acerca de su estado y cuando deberán ser recargados. Los sistemas contra incendio son probados de manera semanal haciendo trabajar las bombas durante 30 minutos.

La inspección de los equipos fijos se realiza mediante inspecciones regulares que incluyen un checklist.

CONCLUSIONES

Métodos de Evaluación de PME

En el caso de una visita de inspección de riesgo debido a la premura del tiempo, el método utilizado para evaluar la perdida máxima estimada o PME es el del What If?, es decir uno debe ponerse en la peor situación que pueda ocurrir en la instalación inspeccionada. Ya que es labor de la empresa en mención el realizar un PHA o una HazOp and HazAn.

Daños a la Propiedad

El PME de daños a la propiedad debe ser considerando siempre el catastrófico, tal como se ha visto en el informe. Aunque la probabilidad sea pequeña el análisis debe girar en torno a la severidad de los daños

Interrupción de Negocios

El daño por interrupción de negocios es en este caso considerablemente más severo ya que las expectativas de ganancia en este negocio son amplias y por lo tanto la pérdida es mucho más severa que en daños a la propiedad debido al tiempo de paralización.

Layout y Construcciones

La distribución de la planta y los materiales que se utilicen para la construcción son fundamentales para este tipo de análisis, ya que la separación de un riesgo mediante la distancia es mucho más efectivo que cualquier sistema contra incendio. El fuego y las llamas necesitan combustible para poder propagarse.

Reducción o Eliminación de Riesgos

En la mayor parte de los negocios se intenta reducir el riesgo mediante separaciones físicas (distancia o muros cortafuego) o cambiando los materiales a utilizar, dejando de lado el uso de inflamables o combustibles.Sin embargo,esto no se puede dar en todas las empresas ya que algunas se ven obligadas a utilizar estos materiales dentro de sus procesos por lo que la única manera de limitar el riesgo es controlando los focos de ignición y que el personal y las instalaciones estén equipadas adecuadamente para la lucha contra incendios.

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GAS TURBINES

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FM Global

1.0 SCOPE

This data sheet provides loss prevention recommendations for gas turbines. It covers both heavy-duty industrial types and aeroderivatives. It also covers *internal* fires and explosions in gas turbines. *External* fire protection is covered in Data Sheet 7-79, *Fire Protection for Gas Turbines*.

1.1 Changes

January 2005. The following changes were done for this revision:

1. Section 2.1.2.1, Maintenance Testing. Overspeed revised from actual to simulated at less than rated speed.

2. Section 2.1.2.6. Revised to be consistent with 2.2.2.6. Actuation of back-up lube oil pump quarterly versus weekly. Quarterly is adequate for verification of functionality. The emergency pump provides further back-up.

2.0 LOSS PREVENTION RECOMMENDATIONS

2.1 Heavy-Duty Industrial Gas Turbine

2.1.1 *Equipment and Processes*

Table 1 is a list of protective devices recommended for heavy-duty industrial gas turbines.

Table 1. Protective Devices for Heavy-duty Industrial Gas Turbines

	Alarm	*Trip*
Flame detectors in combustors		x (in <750 ms.)
Overspeed trip system (see Note 1): Single-shaft: Two-shaft (uncommon, old engines)- Gas-generator rotor Power-turbine rotor		x x x
Thermocouples in thrust bearings pads (≥5 MW) (see Note 2) or proximity probes	x (210–220°F 98–104°C)	x (240–250°F 115–121°C)
High lube oil temperature sensor in each drain line, or thermocouples in journal-bearing pads	x	x
High exhaust temperature	x	x
Exhaust temperature spread	x	
Low lube oil pressure	x	x
Vibration instrumentation (installed) all bearings (≥5 MW)	x	x
Pressure differential across inlet filter	x	
Flow sensors on return lines of external turbine cooling-air systems	x	x
Temperature sensors in return lines of external turbine cooling-air systems	x	
Redundant fuel shutoff valves (Gaseous and liquid fuel, with automatic venting on gaseous fuel, and drain on liquid fuel systems)		
Automatic drain in combustor casing (liquid fuel)		
Position sensor on compressor bleed valve (Failure to open on startup and shutdown, failure to remain closed at speed)		x

Note 1: Gas turbine overspeed trip system design has evolved over the years. Systems commonly found in industry include:
a. Mechanical bolt with single circuit electronic back-up activated by a relay from the main control sensor and circuit
b. Electronic 2 out of 3 voting logic activated by relays from sensors in the main control circuit
c. Electronic 2 out of 3 voting logic activated by sensors and circuitry independent from the main control loop
d. Mechanical bolt primary with independent electronic 2 out of 3 voting logic back-up

Note 2: Some older engines do not incorporate these features.

2.1.2 *Operation and Maintenance*

2.1.2.1 Maintenance Testing

Table 2 shows recommended testing schedules for heavy-duty industrial gas turbine protective devices.

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Two-shaft (uncommon, old engines)-		
Gas-generator rotor		x
Power-turbine rotor		x
Thermocouples in thrust bearings pads (≥5 MW) (see Note 2) or proximity probes	x (210–220°F 98–104°C)	x (240–250°F 115–121°C)
High lube oil temperature sensor in each drain line, or thermocouples in journal-bearing pads	x	x
High exhaust temperature	x	x
Exhaust temperature spread	x	
Low lube oil pressure	x	x
Vibration instrumentation (installed) all bearings (≥5 MW)	x	x
Pressure differential across inlet filter	x	
Flow sensors on return lines of external turbine cooling-air systems	x	x
Temperature sensors in return lines of external turbine cooling-air systems	x	
Redundant fuel shutoff valves (Gaseous and liquid fuel, with automatic venting on gaseous fuel, and drain on liquid fuel systems)		
Automatic drain in combustor casing (liquid fuel)		
Position sensor on compressor bleed valve (Failure to open on startup and shutdown, failure to remain closed at speed)		x

Note 1: Gas turbine overspeed trip system design has evolved over the years. Systems commonly found in industry include:
a. Mechanical bolt with single circuit electronic back-up activated by a relay from the main control sensor and circuit
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Note 2: Some older engines do not incorporate these features.

2.1.2 Operation and Maintenance

2.1.2.1 Maintenance Testing

Table 2 shows recommended testing schedules for heavy-duty industrial gas turbine protective devices.

Table 2. Recommendations for Testing of Emergency Devices on Heavy-Duty Gas Turbines

	Frequency
Vibration Monitoring	
Installed instrumentation, visual readings	Daily
Installed instrumentation, log readings	Weekly
Hand-held instrumentation, take and log readings	Weekly
Actuation of auxiliary lube pump	Quarterly (see Note 3)
Simulated overspeed test (exercise of system components) (See Note 1.)	Every 6 months
Overspeed test (power turbines driving generators) (See Note 2.)	Annually
Calibration of protective instrumentation (See Table 1.)	Annually

Note 1: Gas turbine electronic control systems have simulated overspeed trip functions in which the entire functioning of the overspeed response, signal transmission, and emergency shutoff valve control can be tested in response to a simulated overspeed signal. The test can be conducted while the unit is on line, without actual overspeeding. Such simulated tests are satisfactory, provided they are accompanied by an actual shutdown of the machine using the emergency trip function.

It may be difficult to overspeed a free turbine driving a compressor, or the turbine of a *single-shaft machine* or gas generator because the compressor drag mounts up quickly and resists acceleration of the rotor. A loss involving overspeed of such a turbine has never been reported among insureds of FM Global. Probably the only hazard of overspeed of a turbine driving a compressor involves fracture or separation of the drive shaft or coupling. This would be a very rare event, and, in any case, an actual overspeed test would have to involve decoupling the turbine from the compressor for adequate simulation of the inertia of the overspeeding component. This is entirely impractical for gas generators and single-shaft gas turbines; it is also impractical and probably undesirable for free turbines driving compressors.

Note 2: While turbines driving compressors may be difficult to overspeed, this is not true of free power turbines driving generators. Such an overspeed loss has never been reported among insureds. If a driven generator loses load, the free turbine will overspeed rapidly with relatively little buildup of aerodynamic drag, and the control system must effect a shutdown reliably and rapidly. Annually perform functional tests of overspeed trip system, at below rated speed, to verify integrity. Fuel valves should be tested for leak tightness, and fuel flow should be under manual control during the conduct of these tests to avoid a runaway turbine.

Note 3: Actuation can be performed quarterly if operating procedures require weekly verification that the back-up pump control and load center switches are in "Auto" and pressure switch and pump isolation valves are open.

2.1.2.2 Inspection of Heavy-Duty Industrial Gas Turbines

The inspection intervals recommended in this section are generally typical of industry practice. Intervals recommended by manufacturers may differ take precedence unless there are specific reasons to recommend otherwise.

Following are outlines of inspections recommended for heavy-duty industrial gas turbines:

2.1.2.2.1 Combustion Section Inspection

Recommendation

Initial inspection after installation:

Base-Loaded Units	*Peaking Units (Approx. 1 start of 5–10 hr/day)*
4000 hr	Initial after 2000 hr Second after additional 2000 hr

The schedules for second and subsequent inspections should be based on the conditions found in previous inspections, with the following typical intervals:

Fuel	*Base-Loaded Units*	*Peaking Units*
Natural gas:	8000 hr	6000 hr
Distillate:	6000 hr	4000 hr

Minimum Scope of Work:

Inspection of combustor baskets (or cans) and transition pieces (or combustion annulus) for distortion, cracking or unusual discoloration.

Inspection of fuel nozzles for erosion and obstruction, igniters for proper functioning and intact wiring, and flame detectors for lens condition, soundness of wiring, and specified response.

Inspection for freedom of operation and leak testing of gas valves, fuel oil valves, dual-fuel check valves.

Inspection of fuel manifold drain valves and combustion casing drain valve for freedom of operation.

Inspection of first-stage turbine nozzle vanes as far as is possible from the combustor side; inspection of turbine blades, turbine nozzles, and outer tip seals as far as possible using a borescope.

Inspection of inlet, including operation of anti-icing equipment.

Inspection of thermocouple harness, tubes for pressure sensors, and vibration instrumentation for cracked or broken leads and other possible damage.

Inspection of exhaust duct for warping, cracking, evidence of overheating, as well as for soundness of seals.

2.1.2.2.2 Hot Section (Hot Gas Path) Inspection

Recommendation

For all units and types of service; initial visual inspection after 8000 hr.

Subsequent inspection as indicated by the conditions found in previous inspections, with the following guidelines for second and subsequent inspections:

Fuel	*Base-Loaded Units*	*Peaking Units (Approx. 1 start of 5–10 hr/day)*
Natural gas:	24,000 hr	200 starts unless manufacturer has established a lower limit. (Total hours not to exceed limits for base-loaded units.)
Distillate:	20,000 hr	

Manufacturers may have established more frequent intervals for hot section inspection in the case of some models. These intervals should take precedence over the above.

Minimum Scope of Work:

Removal of upper half of turbine casing:

Inspection of thermal barrier coating (TBC) for evidence of spalling, erosion, thermal fatigue. Inspection, including nondestructive examination (NDE) to whatever extent possible, of rotating blades for corrosion and erosion, impact damage, and thermal-fatigue cracking.

Removal of nozzle diaphragm sections for NDE. Thermal cracking may be found in the nozzle vanes and in the platforms, such as that illustrated for a three-nozzle segment in Figure 1. Manufacturers have standards for action to be implemented in connection with such cracking, ranging from no action to weld repair, to replacement, depending on the locations, lengths and depths of the cracks.

NDE of turbine disks in blade attachment slots and at bolt holes and disk bores for cracks and corrosion to whatever extent possible.

Refurbishment of parts as indicated, blending of nicks, dents and small thermal cracks in rotor blades, blending and weld repair of nicks and thermal cracks in nozzle vanes, and cleaning of cooling passages.

Measurement of axial clearances between stationary nozzle diaphragms and rotating wheels, between blade tips and shrouds, and of labyrinth seals; comparison with manufacturer's specifications and comparison with previous measurements.

For the initial 8000-hr visual inspection, the casing half should be removed, but blades need not be removed. Nozzle-vane segments need be removed insofar as it is necessary to inspect their overall condition, i.e., warping, thermal cracks, hot-spots, indicating inadequate cooling or combustor hot streaks. If serious conditions are evident, such as thermal cracks or dents near the leading- or trailing-edge roof areas of blades, the blades should be removed for repair. Radial and axial clearances should be taken to whatever extent possible.

2.1.2.2.3 Inspection of Externals

Recommendation

For all units and types of service:	*20,000 hr maximum with annual calibration of instrumentation.*

Minimum Scope of Work:

Dismantle and inspection of compressor bleed valve for freedom of operation and possible damage.

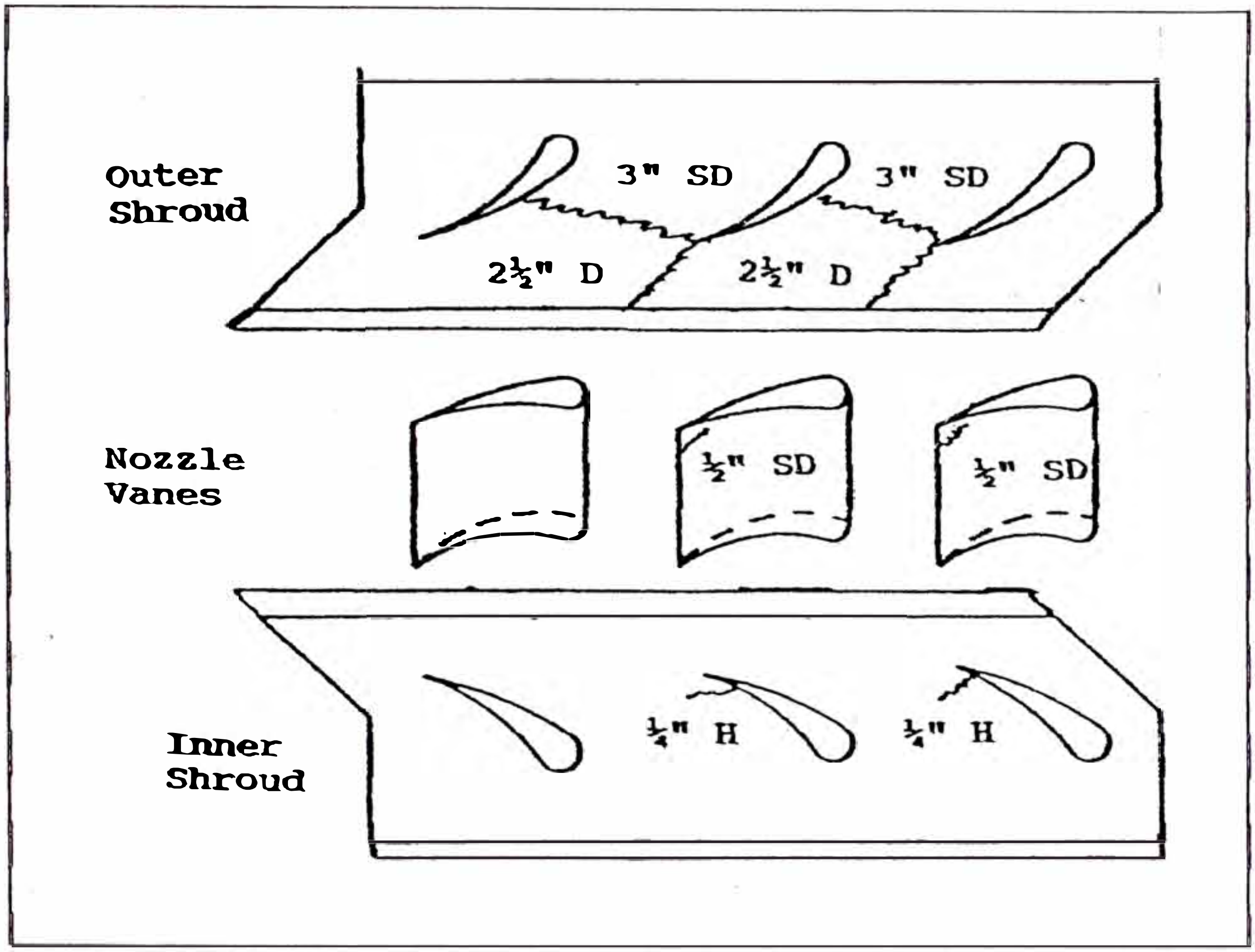

Fig. 1. Sketch of cracking found during hot-section inspection in three-vane turbine nozzle segment in a heavy-duty industrial gas turbine.

Complete checkout of control system for precise functioning and response.

Inspection of coupling, particularly for presence of hard deposits of hydrocarbon sludge in areas of gear teeth.

Bearing alignment.

Inspection of overspeed trip mechanism and calibration of plunger spring tension, if a mechanical trip is used.

Inspection of lubrication system, including pumps, filters, coolers, and instrumentation.

2.1.2.2.4 Overhaul (Including Complete Overhaul of Compressor and Power Turbine)

Recommendation

Base-Loaded Units	*Peaking Units*
On condition (based on performance and vibration monitoring)	Manufacturer's recommendation for compressor disk inspection for low-cycle fatigue cracking.

The only major components that would be revealed for inspection in an overhaul, in contrast with a hot section inspection, are the compressor rotor and stator. The condition of these can be continually checked by monitoring performance of the gas turbine as recommended in Section 3.1.6.

2.1.2.3 Vibration Monitoring

Where fixed vibration instrumentation is in place, a visual check of the vibration reading at each bearing of a heavy-duty industrial gas turbine should be made at least daily and logged weekly.

Vibration signatures are needed to establish a baseline for monitoring and trending equipment performance. Establish new signatures any time an overhaul is performed, and more frequently if adjustments to alignment or balancing are made.

Calibrate all monitoring equipment at least annually. A check against a calibrated hand held portable monitor is satisfactory.

The vibration monitoring procedure described in Data Sheet 17-4, *Monitoring and Diagnosis of Vibration in Rotating Machinery*, should be in effect. Table 1 of Data Sheet 17-4 provides guidance for diagnosis of vibration changes in heavy-duty industrial gas turbines. Bearing vibration is unpredictable. The table presents the most likely causes of a given symptom and suggests the most efficient approaches for investigation. The following discrepancies are covered by the diagnostic methods in the table:

Increase in unbalance caused by fracture of a rotor part;
Bowed or bent shaft;
Disks loose on shaft;
Pedestal looseness, including faulty foundation;
Traverse cracks in shaft;
Buildup of hard deposits in splined coupling;
Gearbox damage;
Buildup of deposits on compressor or turbine blades.

2.1.2.4 Lube Oil Systems

Heavy duty combustion turbine lube oil systems are likely to include one of the following configurations depending on the OEM, the frame size and the age of the system:

a) Two 100% capacity ac lube oil pumps and an emergency dc pump.

b) A main shaft driven pump, one 100% capacity ac motor driven auxiliary pump and an emergency dc motor driven pump.

c) Same as (b) plus a gravity or pressurized drain tank.

The following tests are to determine the full functionality of back-up and emergency supply of lube oil to bearings when the turbine shaft is rotating and the shaft is above temperature limits that may result in bowing if it is allowed to come to rest (reference OEM recommendations). Additionally, for the case of two 100% capacity pumps, even wear between the two is ensured.

Test the standby auxiliary (back-up) lube oil pump at least quarterly by lowering pressure to its actuating sensor, verifying that it will start at the proper pressure and that its output is consistent with the manufacturer's specifications. If a separate emergency lube oil pump is provided, test it quarterly and prior to every startup. Correct and verify by an additional test any deviations from manufacturer's set points.

Record start and stop pressures of auxiliary and emergency lube oil pumps.

Where gravity-type emergency lube-oil systems are used, test the tank low-level alarm at least quarterly.

Lubricating, seal and control oil systems for driven equipment are described in the data sheet for the respective equipment.

2.1.2.5 Lube Oil System Management

The function of lube oil in turbine reliability cannot be overemphasized. An effective monitoring program of a lube oil system condition must be in effect. An acceptable program is based on written documentation setting forth goals and requirements that are acceptable to the manufacturer for the machine application, turbine history, and the risk.

The basic elements of a lube oil management program include but are not limited to the following:

1. Purchase specifications prepared by the plants' engineering department. Such specifications to be included with every purchase order for new oil.

2. To prevent contamination, oil storage to be in a clean, controlled environment.

3. Storage of oil in properly identified sealed containers.

4. Sampling of oil ***prior*** to use to ensure that it is the specified oil and not contaminated.

5. Oil reservoir pre-closure inspection and sign-off to prevent debris from entering the oil system following any maintenance work and following refill.

6. Leak testing all liquid heat exchangers (oil coolers) to ensure that water has not entered the system.

7. Using a qualified lab, do an oil analysis two to four times annually, depending on operating conditions and history. Additionally, conduct an analysis prior to outage planning to obtain information pertinent to the outage.

8. If oil is to be recycled on-site, specifications for the conditioner or centrifuge should specify the oil used, the purity required and the contaminants that could reasonably be encountered.

2.1.2.6 Bearing Alignment

Check the alignment of bearings of heavy-duty industrial gas turbines with those of their driven machines during external inspection. If alignment is made while the set is cold, use valid estimates of pedestal temperatures at operating conditions to set cold offsets so that the bearings will be aligned perfectly at steady-state conditions. A hot alignment at steady-state temperature is a satisfactory alternative if it can be accomplished readily.

For heavy industrial engines alignment is dependent on the heat removal capability of the lubricating oil because it not only lubricates the bearing but removes heat from the pedestals.

2.1.2.7 Performance Monitoring

Ensure the instrumentation defined in Section C.2.2.1 are in place, and the readings recorded continuously.

Ensure a program of performance monitoring, as described in Section 2.2.2.5, is in effect. At a minimum, apply the following schedule of activities:

Monitoring Activity	***Frequency***
Evaluate pressure drop across inlet filter:	**Daily**
Monitor heat rate, output and pressure ratio:	**Daily***
Monitor blade-path spread:	**Daily**
Plot compressor operating points on compressor map for different power settings:	**Weekly****

***If output decreases by 5%, clean the compressor thoroughly. If cleaning the compressor does not restore the output, heat rate and pressure ratio by at least 50% of the reduction, inspect the compressor blading for erosion and/or fouling by hard deposits. In no case should the performance be allowed to deteriorate by more than 10% before corrective action is taken.**

****If the operating point on a compressor map deviates from the typical operating regime in the direction of stall, evaluate the performance of the gas turbine, including the effects of cleaning, for possible overhaul. In no case should the operating point be allowed to move into the surge area as represented by a manufacturer's compressor map.**

2.1.2.8 Protection against Inlet Icing

In climates where icing of the inlet system may occur (below ambient temperatures of 40°F, or 5°C), make provision to prevent ice formation in the inlet system.

Ensure inlet systems also have snow hoods shielding both the main inlet and the blow-in doors.

2.1.2.9 Water Treatment for Evaporative Coolers, Water Injection for Power Augmentation and Compressor Wash

Monitor the quality of the water used in evaporative coolers and follow water quality standards recommended by the gas turbine manufacturer.

2.1.2.10 Treatment of Water Used for NO_x Control

Provide a treatment plant for water injected into the combustor for NO_x control. Adhere to the recommendations of the manufacturer of the gas turbine for water purity.

2.2 Aeroderivative Gas Turbines

2.2.1 *Equipment and Processes*

Table 3 is a list of protective devices recommended for aeroderivative gas turbines:

Table 3. Protective Devices for Aeroderivative Gas Turbines

	Alarm	*Trip*
Flame detectors in combustors		X(in <750 ms)
Overspeed trip (see Note 1) - Gas-generator rotor Power-turbine rotor		X X
Thermocouples in thrust-bearing pads (See Note 2)	X (210–200°F 98–104°C)	X (240–250°F 115–121°C)
High exhaust temperature	X	X
Exhaust temperature spread (See Note 3)	X	
Low lube oil pressure	X	X
Vibration instrumentation installed on casing	X	X
Pressure differential across inlet filter	X	
High lube oil header temperature	X	X
Redundant fuel shutoff valves (Gaseous and liquid fuel, with automatic venting in gaseous fuel, and drain in liquid fuel systems)		
Automatic drain in combustor casing (liquid fuel)		
Chip detector in lube-oil system		

Note 1: Gas turbine overspeed trip system design incorporates electronic 2 out of 2 or 2 out of 3 voting logic. One set is provided for each shaft (including gas generator, power turbine as applicable).

These systems are proven in service with those incorporating electronic 2 out of 3 voting logic having higher reliability and, based on design logic, providing less chance for false trips. Independent governor control/emergency trip circuitry is preferred.

Note 2: Only in power turbines with sliding bearings.

Note 3: Only in newer aeroderivative gas turbines having multiple combustor-basket construction. The recommendation is intended to help prevent high-frequency fatigue of turbine blades as a result of blade vibration excited by uneven combustion; the older units (having multiple-basket construction) have sufficient history to allow the conclusion that this mode of failure is not a serious hazard. There is no loss experience to recommend this instrumentation in aeroderivative units with annular combustors.

2.2.2 *Operations and Maintenance*

2.2.2.1 Maintenance Testing

Table 4 shows recommended testing schedules for aeroderivatives.

Table 4. Recommendations for Testing of Emergency Devices on Aeroderivative Gas Turbines

Recommendations	*Frequency*
Vibration monitoring	
Installed instrumentation, visual readings	Daily
Installed instrumentation, log readings	Weekly
Hand-held instrumentation, take and log readings	Weekly
Actuation of auxiliary lube pump	Weekly
Check of lube-oil metal chip detector	Weekly
Simulated overspeed test (exercise of system components) (See Note 1.)	Every 6 months
Overspeed test—power turbines driving generators (See Note 2.)	Annually
Calibration of protective instrumentation (See Table 3.)	Annually

Note 1: Gas turbine electronic control systems have simulated overspeed trip functions in which the entire functioning of the overspeed response, signal transmission, and emergency shutoff valve control can be tested in response to a simulated overspeed signal. The test can be conducted while the unit is on line, without actual overspeeding. Such simulated tests are satisfactory, provided they are accompanied by an actual shutdown of the machine using the emergency trip function.

Note 2: While turbines driving compressors may be difficult to overspeed, this is not true of free turbines driving generators. FM Global has never reported such an overspeed loss. If a driven generator loses load, the free turbine will overspeed rapidly with relatively little buildup of aerodynamic drag, and the control system must effect a shutdown reliably and rapidly. Test fuel valves should be tested for leak tightness. During testing, manually control fuel flow to avoid a runaway turbine.

Perform functional tests of the overspeed trip systems annually. Perform tests at less than rated speed using signal generators to verify integrity.

2.2.2.2 Inspection of Aeroderivative Gas Turbines

The inspection intervals recommended in this section are generally typical of industry practice. Intervals recommended by manufacturers may differ and some manufacturers gio by equivalent hours; others by a combination of hours and starts, manufacturers recommendations take precedence unless there are specific reasons to recommend otherwise.

In addition to fuel type, the type of a start (time), trips of fuel load, and power augmentation are factors that well accelerate life cycle utilization and more frequent inspections on a calendar basis. Some manufacturers go by equivalent hours; a thus by a combination of hours and starts.

Following are recommendations for inspections of aeroderivative gas turbines.

2.2.2.2.1 *External Inspection*

Base-Loaded Units	*Peaking Units (Approx. 1 start of 5–10 hr per day)*
4000 hr	2000 hr

Minimum Scope of Work:

Inspection of combustor or combustor baskets (or cans) and transition pieces for distortion, cracking or unusual discoloration.

Inspection of fuel nozzles for erosion and obstruction, igniters for proper functioning and intact wiring, and flame detectors for lens condition, soundness or wiring, and specified response.

Inspection for freedom of operation and leak testing of gas valves, fuel oil valves, dual-fuel check valves.

Inspection of fuel manifold drain valves and combustion casing drain valve for freedom of operation.

Inspection of first-stage turbine nozzle vanes as far as is possible from the combustor side; inspection of turbine blades, turbine nozzle vanes, and outer tip seals as far as possible using a borescope.

Inspection of inlet, including operation of anti-icing equipment.

Inspection of thermocouple harness, tubes for pressure sensors, and vibration instrumentation for cracked or broken leads and other possible damage.

Inspection of exhaust duct for warping, cracking, evidence of overheating, as well as for soundness of the seals.

2.2.2.2.2 *Hot Section Inspection*

Recommendation

Fuel	*Base-Loaded Units*	*Peaking Units (Approx. 1 start of 5–10 hrs/day)*
Natural gas:	25,000 hr	200 starts unless manufacturer has established a lower limit.
Distillate:	18,000 hr	(Total hours not to exceed limits for base-loaded units).

Manufacturers may have established smaller intervals for hot-section inspections in the case of some models. These smaller intervals should take precedence over the above.

Minimum Scope of Work:

Removal of gas generator from the gas turbine enclosure; unbolting of hot-section subassemblies for access to high-pressure and low-pressure turbines.

Inspection, including nondestructive examination (NDE) to whatever extent possible, of rotating blades for corrosion and erosion, impact damage, and thermal-fatigue cracking.

Removal of nozzle diaphragm sections for NDE. Thermal cracking and/or bowing may be found in the nozzle vanes, as illustrated in Figures 2 and 3. Manufacturers have standards for action to be implemented in connection with such cracking, ranging from no action to weld repair, to replacement, depending on the locations, lengths and depths of the cracks.

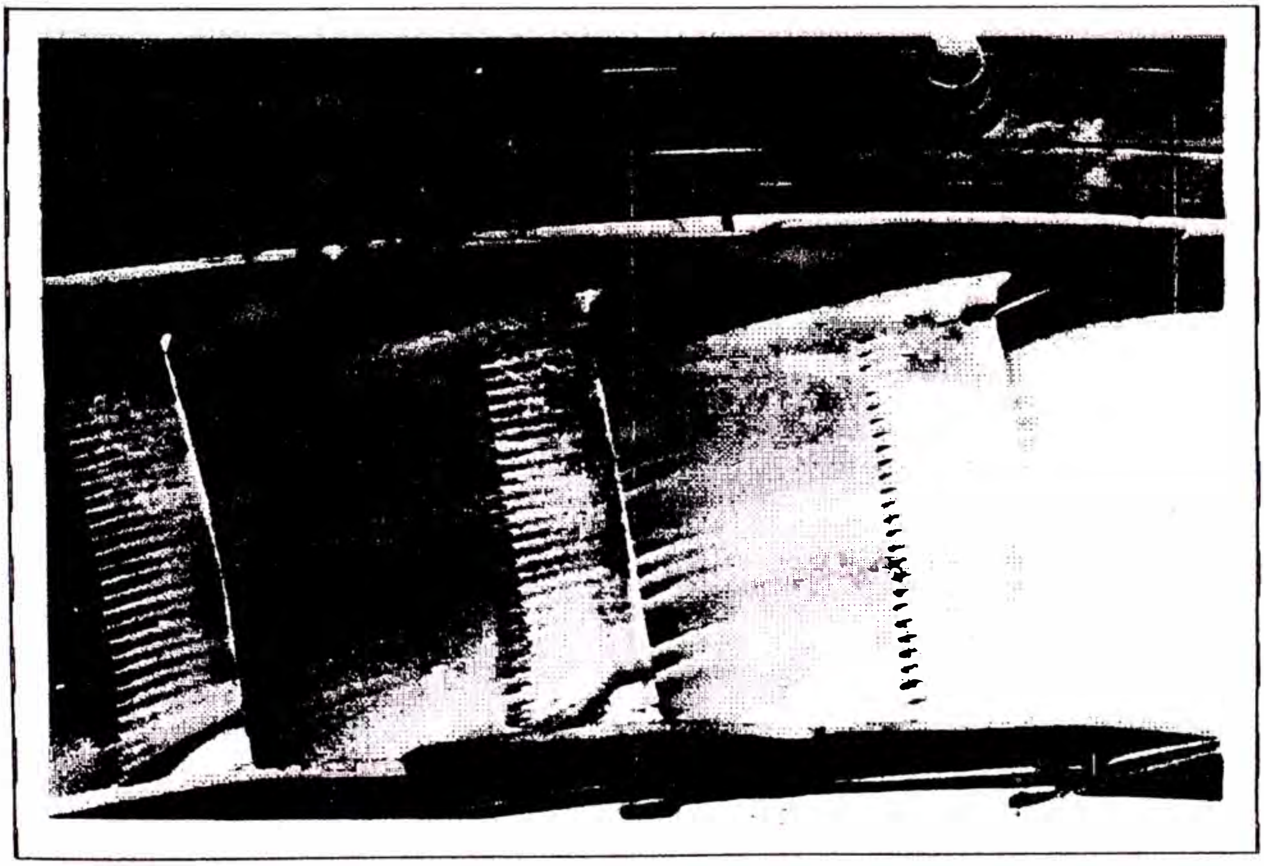

Fig. 2. Turbine nozzle vane cracks typical of aeroderivative gas turbine.

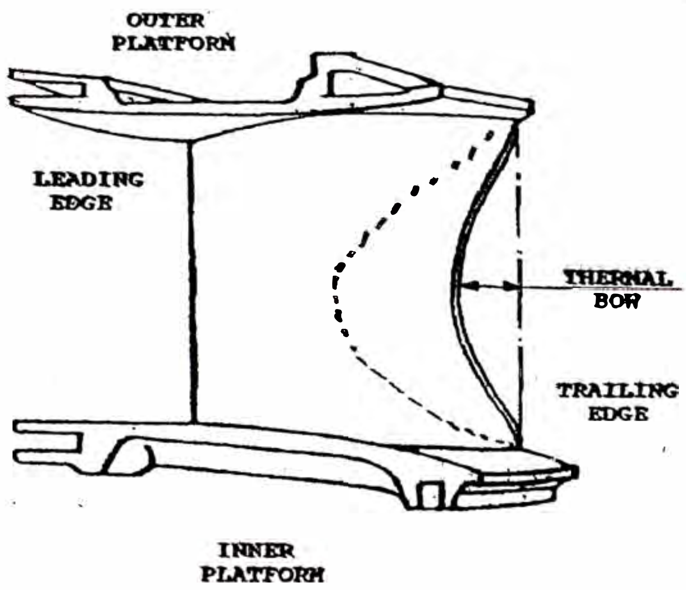

Fig. 3. Bowing of trailing edge of aeroderivative gas turbine.

NDE of turbine disks in blade attachment slots and at bolt holes and disk bores for cracks and corrosion to whatever extent possible.

Refurbishment of parts as indicated, blending of nicks, dents and small thermal cracks in rotor blades, blending and weld repair of nicks and thermal cracks in nozzle vanes, and cleaning of cooling passages.

Measurement of axial clearances between stationary nozzle diaphragms and rotating wheels, between blade tips and shrouds, and of labyrinth seals; comparison with manufacturer's specifications and comparison with previous measurements.

Additional work as recommended in manufacturer's inspection procedures.

2.2.2.2.3 *Overhaul (Including Complete Overhaul of High-Pressure and Low-Pressure Compressors, and of the Power Turbine)*

Recommendation

Base-Loaded Units	*Peaking Units*
On condition (based on performance and vibration monitoring)*	Manufacturer's recommendation for compressor disk inspection for low-cycle fatigue cracking.

*For base-loaded units firing natural gas, this interval may be as much as 50,000 hrs.

The only major components that would be revealed for inspection in an overhaul, in contrast with a hot-section inspection, are the compressor rotors and stators, and the power turbine. The condition of the compressors can be continually checked by monitoring performance of the gas turbine as recommended in Section 2.1.2.5. The major hazard in power turbines is low-cycle fatigue as a result of an excessive number of starts. This is a hazard primarily in peaking units. The manufacturer should be asked for a cyclic limit for power turbines in peaking units; the condition of rolling-element bearings (which may be inaccessible without a major teardown) can be assessed at frequent intervals by vibration monitoring and inspection of the lube-oil metal detector. These bearings should be changed out in accordance with the life limits established by the bearing manufacturer.

2.2.2.3 Vibration Monitoring (Aeroderivative Gas Turbines)

Vibration instrumentation is installed on the casings of aeroderivative gas generators and some power turbines, rather than directly on the bearings. Where sliding bearings are used in power turbines, the instrumentation should be mounted on the bearings.

Where fixed vibration instrumentation is in place, a visual check of the vibration reading at each instrument location should be made at least daily and logged weekly.

The vibration monitoring procedure described in Data Sheet 17-4, *Monitoring and Diagnosis of Vibration in Rotating Machinery*, should be in effect. Data Sheet 17-4 provides guidance for diagnosis of vibration changes in gas turbines. Bearing vibration is unpredictable. The table presents the most likely causes of a given symptom and suggests the most efficient approaches for investigation. The following discrepancies are covered by the diagnostic methods in the table:

Increase in unbalance caused by fracture of a rotor part.
Bowed or bent shaft
Disks loose on shaft
Pedestal looseness, including faulty foundation.
Transverse cracks in shaft
Buildup of hard deposits in splined coupling.
Gearbox damage.
Buildup of deposits on compressor or turbine blades.
Rolling-element bearing damage.

Vibration signatures are needed to establish a baseline for monitoring and trending equipment performance. Establish new signatures any time an overhaul is performed, and more frequently if adjustments to alignment or balancing are made.

Calibrate all monitoring equipment at least annually. A check against a calibrated hand held portable monitor is satisfactory.

The gas generator for aeroderivative gas turbines have ball or rolling-element bearings. Monitor changes in high-frequency vibration that might indicate deterioration of the rolling elements by weekly analysis of the vibration signal to detect vibration increases at roller or ball passing frequency (approximately one-half times rpm × number of rolling elements).

2.2.2.4 Lube Oil Systems

Aeroderivative combination turbines normally include ball or roller bearings. The lube oil supply pump and scavenge pump are driven from the accessory gear box for the engine. The scavenge pumps remove oil from the bearing sumps and deliver it to an external reservoir, filter and cooling systems. Because of the bearing design, lube oil supply is not required to the engine during start-up and shutdown. Pressure and temperature switches are provided to alarm and/or trip if threshold limits for critical parameters are exceeded.

The critical bearings are those of the driven equipment which are normally Babbitted journal bearings. Lube oil systems for these are described in the respective driven equipment data sheet.

2.2.2.5 Lube Oil System Management

The function of lube oil in turbine reliability cannot be overemphasized. An effective monitoring program of a lube oil system condition must be in effect. An acceptable program is based on written documentation setting forth goals and requirements that are acceptable to the manufacturer for the machine application, turbine history, and the risk.

The basic elements of a lube oil management program include but are not limited to the following:

1. Purchase specifications prepared by the plants' engineering department. Such specifications to be included with every purchase order for new oil.

2. To prevent contamination, oil storage to be in a clean, controlled environment.

3. Storage of oil in properly identified sealed containers.

4. Sampling of oil *prior* to use to ensure that it is the specified oil and not contaminated.

5. Oil reservoir pre-closure inspection and sign-off to prevent debris from entering the oil system following any maintenance work and following refill.

6. Leak testing all liquid heat exchangers (oil coolers) to ensure that water has not entered the system.

7. Using a qualified lab, do an oil analysis two to four times annually, depending on operating conditions and history. Additionally, conduct an analysis prior to outage planning to obtain information pertinent to the outage.

8. If oil is to be recycled on-site, specifications for the conditioner or centrifuge should specify the oil used, the purity required and the contaminants that could reasonably be encountered.

2.2.2.6 Bearing Alignment

Check the alignment of bearings of the power turbines of aeroderivative gas turbines with those of their driven machines. If alignment is made while the set is cold, use valid estimates of pedestal temperatures at operating conditions to set cold offsets so that the bearings will be aligned perfectly at steady-state conditions. A hot alignment at steady-state temperatures is a satisfactory alternative if it can be accomplished readily.

2.2.2.7 Performance Monitoring (Aeroderivative Gas turbines)

Ensure the instrumentation defined in Section C.3.2 are in place, and the readings recorded continuously. In dual-rotor aeroderivatives, Sense pressure and temperature at Sta. 2.5 (between the low-pressure and high-pressure compressors) and continuously record on engine performance logs.

Ensure a program of performance monitoring, as described in Section C.2.1, is in effect. At a minimum, implement the following schedule of activities:

Monitoring Activity	*Frequency*
Evaluate pressure drop across inlet filter	Daily
Monitor heat rate, output, and pressure ratio	Daily*
Monitor blade path spread (Where applicable)	Daily
Plot compressor operating points on low-pressure and high-pressure compressor maps for different power settings	Weekly**

*If output decreases by 5% clean the compressor thoroughly. If cleaning the compressor does not restore the output, heat rate and pressure ratio by at least 50% of the reduction, inspect the compressor blading for erosion and/or fouling by hard deposits. Do not allow the performance to deteriorate by more than 10% before corrective action is taken.

**If the operating point on a compressor map deviates from the typical operating regime in the direction of stall, evaluate the performance of the gas turbine, including the effects of cleaning, for possible overhaul. (See Section 3.2.1.2.4.) Do not allow the operating point to move into the surge area as represented by a manufacturer's compressor map.

2.2.2.8 Protection against Inlet Icing

In climates where icing of the inlet system may occur (below ambient temperatures of 40°F or 5°C), make provisions to prevent ice formation in the inlet system. There are numerous approaches to providing such protection.

Ensure inlet systems also have snow hoods shielding both the main inlet and the blow-in doors.

2.2.2.9 Water Treatment for Evaporative Coolers

Follow gas turbine manufacturers recommendations for water quality to be used in evaporative coolers.

2.2.2.10 Treatment of Water Used for NO_x Control

Provide a treatment plant for water injected into the combustor for NO_x control. Adhere to the recommendations of the manufacturer of the gas turbine for water purity, with a maximum of 1 ppm sodium or potassium.

2.3 Alerts

Original equipment manufacturers (OEM) issue technical alerts when design or operating problems occur which differ from expectations. Alerts are specific to engine model numbers, version, and in some cases, inspection interval and hours/starts.

The technical risk urgency may very from one requiring immediate shutdown to inspect at next opportunity, etc.

Clients are requested to keep FM Global advised of the implementation plans for all active alerts issued to them that affect the gas turbines and any associated system loss prevention.

3.0 SUPPORT FOR RECOMMENDATIONS

3.1 Loss Prevention Issues in Gas Turbines

Major manufacturers are continuing to enhance designs to increase capacity. This generally means increased compression ratio, increased mass flow, increased firing temperature or a combination of those parameters. Manufacturers are also changing materials of construction, particularly in the hot gas path (Combustion and Turbine sections) of the engines to increase component life cycle.

4.0 REFERENCES

Data Sheet 5-12, *Electric AC Generators*

Data Sheet 5-23, *Emergency and Standby Power Systems.*

Data Sheet 7-79 *Fire Protection for Gas Turbines.*

Data Sheet 13-17, *Gas Turbines.*

Data Sheet 17-1, *Nondestructive Examination.*

Data Sheet 17-4, *Monitoring and Diagnosis of Vibration in Rotating Machinery.*

APPENDIX A GLOSSARY OF TERMS

Aeroderivative Gas Turbine: as the name implies, aeroderivative gas turbines are derived from aircraft jet or fanjet engines. The first aeroderivatives were installed about 1960. They were used as gas compressor drives in gas pipelines, where inexpensive natural gas was available as a fuel. They were also used as peaking units in electric generating plants because they have low efficiency and fuel was relatively expensive. More recently they are used in continuous duty in combined-cycle plants in utilities and in cogeneration plants.

Heavy-Duty Industrial Gas Turbine: the category of heavy-duty industrial gas turbine applies to any gas turbine manufactured solely for use in industry have substantial mass for long life expectancy, as distinct from aeroderivative gas turbines, which are derived from aircraft engines of lightweight construction.

APPENDIX B DOCUMENT REVISION HISTORY

January 2005. The following changes were done for this revision:

1. Section 2.1.2.1, Maintenance Testing. Overspeed revised from actual to simulated at less than rated speed.

2. Section 2.1.2.6. Revised to be consistent with 2.2.2.6. Actuation of back-up lube oil pump quarterly versus weekly. Quarterly is adequate for verification of functionality. The emergency pump provides further back-up.

May 2003. Minor editorial changes were done for this revision.

January 2001. This revision of the document was reorganized to provide a consistent format.

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TRANSFORMERS

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1.0 SCOPE

This data sheet provides electrical protection recommendations for the prevention of losses in power and distribution transformers. It also provides fire protection recommendations for power, distribution, arc furnace and induction furnace transformers. Loss experience and test information is provided as support for these recommendations.

1.1 Changes

January 2005. The following changes were done for this revision:

1. Section 2.2 Indoor Transformers, recommendations 2.2.1.2.2 & 2.2.1.3.2.2. A protection alternate to CO-2 of an FM Approved gaseous agent protection system or a water mist system FM Approved for machinery spaces is recommended. Also, where automatic sprinkler protection is used, the density has been increased to 0.3 gpm/ft^2 (15 mm/min) from 0.2 gpm/ft^2 (10 mm/min).

2. Section 2.3 Outdoor Transformer, recommendation 2.3.1.2.3 for open pit containment system. Where automatic sprinkler protection is used, the sprinkler density has been increased to 0.3 gpm/ft^2 (15 mm/min) from 0.15 gpm/ft^2 (6 mm/min). Where a flame arrestor is used to increase the amount of time before burning oil enters the pit Size No 5 rather than Size No 2 ASTM D448 Standard Classification for Sizes of Aggregate for Road and Bridge Construction should be used. Size No 5 is closer to the 1.5 in (3.8 cm) washed and uniformly sized rock tested at the FM Global Research Campus.

3. Section 3.1.1, Approved and Equivalent Transformer. A transformer equivalent to an FM Approved transformer is defined as a transformer with a UL listing per NEC Section 450-23 with electrical protection to clear sustained low current faults. The reference to NEC 450-23 was left out of the previous edition. Transformers complying with NEC 450-23 include four of the five safeguards requested for an FM Approved transformer. Low current fault protection is the remaining safeguard.

1.2 Superseded Information

This data sheet supersedes the January 1997 edition with revisions of September 1998.

2.0 LOSS PREVENTION RECOMMENDATIONS

Conventional power and distribution transformers are reliable devices having low electrical failure rates. If the transformer is FM Approved (see Appendix A for definition), or equivalent, which involves the use of a less flammable insulating liquid and electrical and mechanical protection, and is not a network, arc furnace, induction furnace or generator step-up transformer, the failure frequency is considered low enough to be acceptable without fire protection. For other transformer types, there are the potentials for either an internal or an external electrical fault which results in overpressure of the transformer. If increase in pressure is rapid the pressure relief device may not be adequate to prevent tank failure of the transformer. Tank failure may release substantial quantities of insulating liquid. If fire occurs, the resulting property damage depends on the amount and type of liquid and whether buildings or other equipment are exposed.

2.1 Electrical Protection

2.1.1 Electrical

2.1.1.1 Each transformer, depending on its criticality, and whether it presents a fire exposure, should have a protection system as determined by an accurate engineering study. This protection system should be functionally equivalent to the protection illustrated in Figures 1a through 1e. Table 1 summarizes the various devices available for the electrical protection of transformers.

Table 1. Electrical Protection

Device Number	*Device Name*	*Device Description*
FUSE	Expulsion-type.	Provides protection for both internal and external faults. Current limiting type. Provides internal fault protection and limitation of fault current levels.
24	Volts per Hertz relay.	A relay that functions when the ratio of voltage to frequency exceeds a preset value. Used on unit connected transformers.
26	Thermal device.	A device that functions when the transformer liquid temperature exceeds a predetermined value. (Other than the transformer winding temperature as covered by device 49)
49	Thermal relay.	A relay that functions when the transformer winding temperature or other load carrying element exceeds a predetermined value.
50G[1]	Zero sequence instantaneous ground overcurrent relay.	A relay that functions instantaneously when the ground fault current exceeds a predetermined value. Use when time coordination is not required. Device 50G is connected to a toroidal CT. Device 50G provides ground fault protection for the transformer wye winding and through faults.
50GD[2]	Zero sequence instantaneous ground overcurrent relay.	A relay that functions instantaneously when the ground fault current exceeds a predetermined value. Device 50GD is connected to a toroidal CT on the delta winding conductors. Device 50GD provides ground fault protection for the transformer delta winding and the transformer leads between the winding and the toroidal CT.
50N[1]	Instantaneous ground overcurrent relay.	A relay that functions instantaneously when the ground fault current exceeds a predetermined value. The relay is connected in the transformer neutral. Device 50N provides ground fault protection for the transformer wye winding and through faults. The relay is set for either high magnitude ground faults for use with 51N, or sensitively to be used alone when time coordination is not required.
50ND[2]	Instantaneous ground overcurrent relay.	A relay that functions instantaneously when the ground fault current exceeds a predetermined value. The relay is residually connected in the CT secondary on the delta winding conductors. Device 50ND provides high magnitude ground fault protection for the transformer delta winding and the transformer leads between the winding and the CT.
50NY[1]	Instantaneous ground overcurrent relay.	A relay that functions instantaneously when the ground fault current exceeds a predetermined value. The relay is residually connected in the CT secondary on the wye winding conductors. Device 50NY provides ground fault protection for primary wye windings, back fed secondary windings and through faults occurring downstream of the secondary wye winding. It is set for either high magnitude ground faults for use with 51NY, or sensitively to be used alone when time coordination is not required.
50TF	Instantaneous phase overcurrent relay.	A relay that functions instantaneously on an excessive value of current. Provides protection for transformer internal faults.
51N[1]	AC time ground overcurrent relay.	A relay that functions when the ground fault current exceeds a predetermined value for a given time. The current and operating time are inversely proportional. The relay is connected in the transformer neutral. Device 51N provides ground fault protection for the transformer wye winding and through faults occurring downstream of the secondary wye winding.
51ND[2]	AC time ground overcurrent relay.	A relay that functions when the ground fault current exceeds a predetermined value for a given time. The current and operating time are inversely proportional. The relay is residually connected in the CT secondary. Device 51ND provides ground fault protection for the transformer delta winding and the transformer leads between the winding and the CT.
51NY[1]	AC time ground overcurrent relay.	A relay that functions when the ground fault current exceeds a predetermined value for a given time. The current and operating time are inversely proportional. The relay is residually connected in the CT secondary. Device 51NY provides ground fault protection for primary wye windings, back fed secondary wye windings, and through faults occurring downstream of the secondary wye winding.
51TF	AC time overcurrent relay.	A relay that functions when the ac input current exceeds a predetermined value. The input current and operating time are inversely proportional. Provides transformer through fault and backup protection.
51TL	AC time overcurrent relay.	A relay that functions when the ac input current exceeds a predetermined value. The input current and operating time are inversely proportional. Provides transformer overload protection.

Device Number	Device Name	Device Description
63	Pressure switch or relay.	A switch or relay which operates on given values, or on a given rate of change of pressure.
67N[3]	AC directional neutral overcurrent relay.	A relay that functions on a desired value of ground fault current in a predetermined direction. Provides ground fault protection of the transformer wye winding for only internal faults.
71	Liquid level gauge.	Measures the level of insulating liquid in the transformer tank.
87T	Transformer differential relay.	A relay that functions on a percentage difference of the primary and secondary side currents. Provides fault protection for the transformer for only internal faults.
87TN[3]	Transformer ground differential relay.	A relay that functions on a predetermined difference between neutral and phase residual currents for a transformer ground fault. Provides ground fault protection of the transformer wye winding for only internal faults.

Notes:
1. Devices 50G, 50N/51N, and 50NY/51NY are alternatives.
2. Device 50GD is an alternative to 50ND/51ND.
3. Device 67N is an alternative to 87TN.

2.1.1.2 Provide ground fault protection on both sides of the transformer at each voltage level in a facility. Each voltage level has its own unique system ground and, therefore, must have its own ground fault protection system with appropriate tripping and/or alarm. Provide system ground fault protection in accordance with the recommendations in Data Sheet 5-10, *Protective Grounding for Electric Power Systems and Equipment*. Depending upon the type of system grounding, these devices should trip the upstream (high side) breaker if provided or alarm at a constantly attended location (e.g., Fig. 1a). The alarm should be treated as a fire event and responded to appropriately. An alarm response procedure should be developed and posted. The Plant Emergency Organization should include both fire and electrical personnel capable of de-energizing the equipment. If de-energization can not be accomplished in a timely manner, then a high side breaker must be installed and tripped (e.g., Fig. 1b).

2.1.1.3 An arc monitoring system ABB Arc Guard System or FM Approved equivalent should be provided to detect arcing faults in transformer vaults with exposed energized components. This additional protection should be provided where the ground fault relay cannot be set low enough to detect ground fault current due to neutral imbalance current flow. These devices, in conjunction with the ground fault protection in Section 2.1.1.2, should trip the upstream (high side) breaker if provided or alarm at a constantly attended location. The alarm should be treated as a fire event and responded to appropriately. An alarm response procedure should be developed and posted. The Plant Emergency Organization should include both fire and electrical personnel capable of de-energizing the equipment. If de-energization cannot be accomplished in a timely manner, then a high side breaker must be installed and tripped (e.g., Fig. 1b).

Figure 1a is for all transformers rated 1000 to 10000 kVA with primary fuses. The table in Figure 1a shows the recommended protective devices for dry-type transformers, and 1000- to 5000-kVA and 5000- to 10000-kVA liquid insulated transformers. The table also shows the action (I—Indication, A—Alarm, or T—Trip) of the protective device for the three categories of transformers. Figure 1a also applies to transformers rated less than 1000 kVA when the transformer creates a fire exposure. Alternative protective devices are shown in Figure 1e.

Figure 1b is for all transformers rated 1000 to 10000 kVA with primary circuit breakers. The table in Figure 1b provides the same information as described for Figure 1a. Figure 1b also applies to transformers rated less than 1000 kVA when the transformer creates a fire exposure. Alternative protective devices are shown in Figure 1e.

Figure 1c is for transformers rated 10,000 kVA and above. Alternative protective devices are shown in Figure 1e.

Figure 1d is a typical relay diagram for a dual supply and dual transformer configuration (secondary selective system).

Figure 1e shows all of the protective devices described. Other schemes are available that provide equivalent protection and reliability. The protection for ungrounded and high resistance grounded systems is not covered by Figures 1a through 1e. Appropriate ground fault protection should be provided.

Device No.	Description	Dry	Liquid (MVA) 1–5	Liquid (MVA) 5–10
26	Liquid thermal device		I	I
49	Winding thermal device	I		I
51N[1]	Time delay overcurrent relay. (Ground fault protection of transformer wye winding and through faults.)	T	T	T
51TL	Time delay overcurrent relay. (Transformer overload protection)	T	T	T
63	Sudden pressure relay			T
71	Liquid Level Device		I	I

Notes:
A—Alarm, I—Indication, T—Trip
1. Devices 50G, 50N/51N, 50NY/51NY, 67N and 87TN are alternatives. (See Fig 1E.)

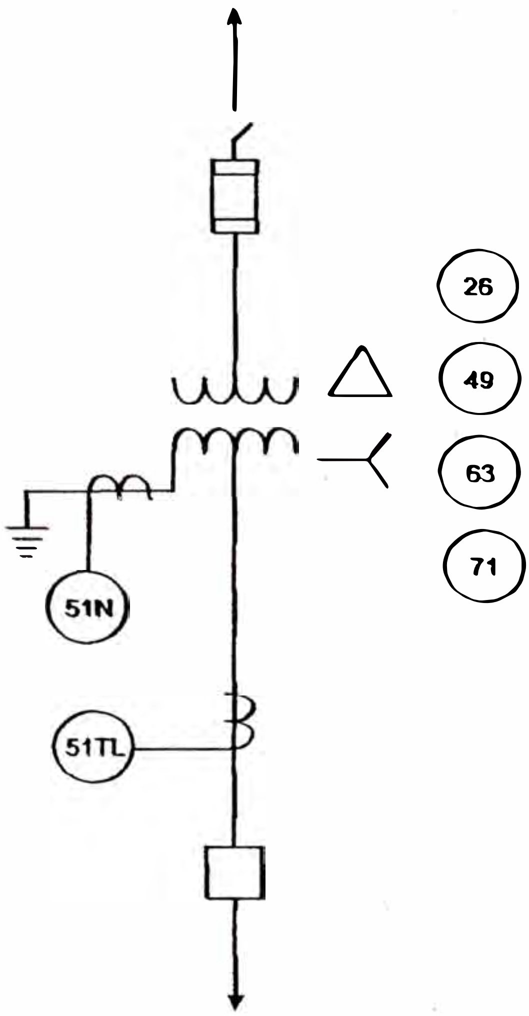


Fig. 1A. Electrical protection one-line. Primary fuse.
1000- to 10000-kVA transformers.
Less than 1000 kVA when transformer creates fire exposure.

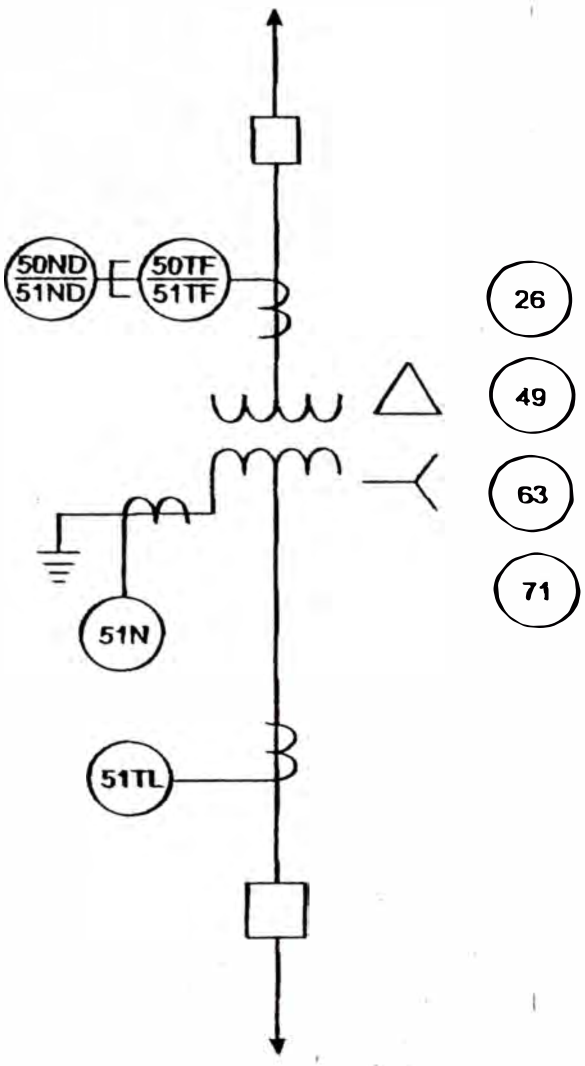
2.1.2 *Operation and Maintenance*

2.1.2.1 Transformers should be installed, operated and maintained in accordance with manufacturers' recommendations.

2.1.2.2 When a transformer is delivered empty of liquid, the manufacturer's instructions must be strictly followed in regard to drying and liquid-filling procedures.

2.1.2.3 Before commissioning, transformers should be inspected and tested in accordance with manufacturers' instructions. Dielectric characteristics of the insulation media (winding insulation, insulating liquid, bushings, tap changer oil) should be measured and recorded to establish bench marks for future reference. Refer to Data Sheet 5-20, *Electrical Testing*. The transformer should be energized if it is to be stored for a lengthy period.

Device No.	Description	Dry	Liquid (MVA) 1–5	Liquid (MVA) 5–10
26	Liquid thermal device.		I	I
49	Winding thermal device.	I		I
50ND[2]	Instantaneous ground overcurrent relay. (High magnitude ground fault protection of transformer delta winding and leads.)	T	T	T
50TF	Instantaneous overcurrent relay. (High magnitude transformer internal phase fault protection.)	T	T	T
51N[1]	Time delay overcurrent relay. (Ground fault protection of transformer wye winding and through faults.)	T	T	T
51ND[2]	Time delay ground overcurrent relay. (Ground fault protection of transformer delta winding and leads.)	T	T	T
51TF	Time delay overcurrent relay. (Phase through fault protection.)	T	T	T
51TL	Time delay overcurrent relay. (Transformer overload protection)	T	T	T
63	Sudden pressure relay			T
71	Liquid level device		I	I

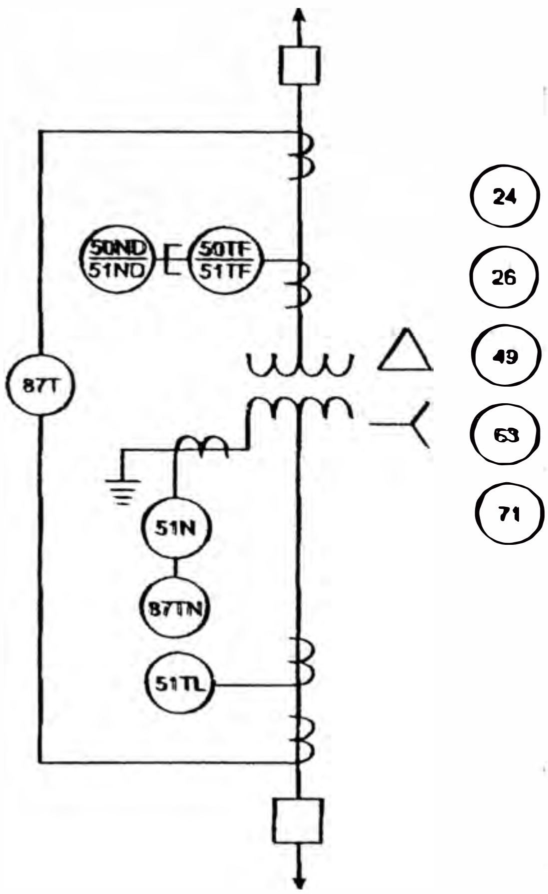


Notes:
A—Alarm, I—Indication, T—Trip
1. Devices 50G, 50N/51N, 50NY/51NY, 67N and 87TN are alternatives. (See Fig 1E.)
2. Device 50GD is an alternative to 50ND/51ND. (See Fig 1E.)

Fig. 1B. Electrical protection one-line. Primary breaker.
1000- to 10000-kVA transformers outdoors.
Less than 1000 kVA when transformer creates fire exposure.

2.1.2.4 Immediately after commissioning and periodically for several days, the transformer should be inspected thoroughly for indications of overheating, oil leaks, vibration or malfunction. Proper operation and calibration of each monitoring and protective device should be verified. Dissolved-gas-in-oil analysis should be performed within 18 to 24 hours after energization, one month later, and six months later to determine if the transformer is having a gassing problem.

Device No.	Description	Action
24	Volts/hertz relay (For unit connected transformers only)	T
26	Liquid thermal device	A
49	Winding thermal device	A
50ND[2]	Instantaneous ground overcurrent relay. (High magnitude ground fault protection of transformer delta winding and leads.)	T
50TF	Instantaneous overcurrent relay. (High magnitude transformer internal phase fault protection)	T
51N[1]	Time delay overcurrent relay. (Ground fault protection of transformer wye winding and through faults.)	T
51ND[2]	Time delay ground overcurrent relay. (Ground fault protection of transformer delta winding and leads.)	T
51TF	Time delay overcurrent relay. (Phase through fault protection.)	T
51TL	Time delay overcurrent relay. (Transformer overload protection)	T
63	Sudden pressure relay	T
71	Liquid Level Device	I
87T	Transformer differential relay (Fault protection for transformer internal faults)	T
87TN[3]	Transformer ground differential relay (Ground fault protection of transformer wye winding internal faults)	T



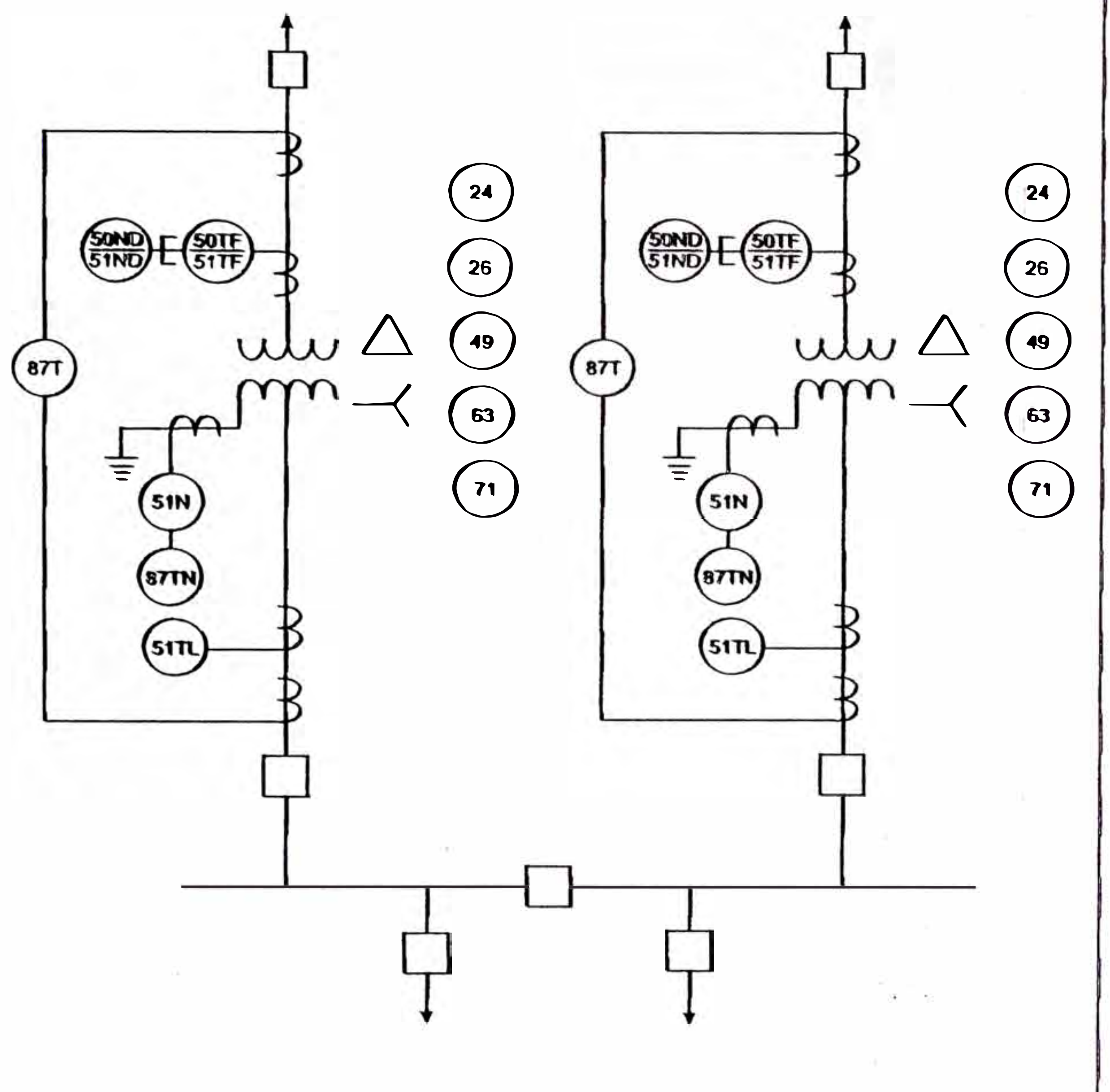
Notes:
A—Alarm, I—Indication, T—Trip
1. Devices 50G, 50N/51N, and 50NY/51NY are alternatives. (See Fig 1E.)
2. Device 50GD is an alternative to 50ND/51ND. (See Fig 1E.)
3. Device 67N is an alternative to 87TN. (See Fig 1E.)

Fig. 1C. Electrical protection one-line. 10000-kVA and larger transformers.

2.1.2.5 The operation of each transformer should be monitored on a fixed schedule. Overheating caused by continuous overloading, overexcitation, etc. should be corrected immediately. If a temporary overloading becomes necessary because of outages of other units, switching operations or other reasons, the latest revisions of ANSI/IEEE Standards C57.91 and C57.92 should be followed.

2.1.2.6 Perform electrical testing on all transformers whose failure would cause serious property damage and/or production interruption. Testing should be performed in accordance with manufacturers' instructions in conjunction with Data Sheet 5-20, *Electrical Testing*.

2.1.2.7 All component parts (both in air and under liquid) associated with the automatic operation of the transformer's load tap changer should receive periodic preventive maintenance. Tests should be performed on the mineral oil in the load tap-changer compartment. Low oil level in the tap changer compartment should be investigated. Periodic preventive maintenance on load-tap changers should be performed in accordance



Note:
Electrical protection shown for 10-MVA and larger transformers.
Protection should be chosen per Fig. 1A, 1B, or 1C depending upon transformer size.

Fig. 1D. Electrical protection one-line. Secondary selective system.

with the tap changer manufacturer's instructions, operating experience and recommended practice. The oil-filled load-tap changer compartment should be provided with a mechanical over-pressure relief device. Replacement parts for the load-tap changer should be readily available. The no-load tap changer operating mechanism should be locked to prevent inadvertent operation.

2.1.2.8 Condenser-type bushings should be tested for an increase in power factor and capacitance with time. The bushings should be tested in accordance with manufacturers' instructions and Data Sheet 5-20, *Electrical Testing*, for high power factors and capacitance values. If test results exceed manufacturers' limits for power factor and/or capacitance, they should be removed from service.

Device No.	Description
24	Volts/hertz relay (For unit connected transformers only)
26	Liquid thermal device
49	Winding thermal device
50G[1]	Zero sequence instantaneous ground overcurrent relay. (Ground fault protection of wye winding and through faults)
50GD[2]	Zero sequence instantaneous ground overcurrent relay. (Ground fault protection of transformer delta winding.)
50N	Instantaneous ground overcurrent relay. (High magnitude ground fault protection of wye winding and through faults.)
50ND	Instantaneous ground overcurrent relay. (High magnitude ground fault protection of transformer delta winding and leads.)
50NY	Instantaneous ground overcurrent relay. (High magnitude ground fault protection of wye winding and through faults.)
50TF	Instantaneous overcurrent relay. (High magnitude transformer internal phase fault protection)
51N	Time delay overcurrent relay. (Ground fault protection of transformer wye winding and through faults.)
51ND	Time delay ground overcurrent relay. (Ground fault protection of transformer delta winding and leads.)
51NY	Time delay overcurrent relay. (Ground fault protection of transformer wye winding and through faults.)
51TF	Time delay overcurrent relay. (Phase through fault protection.)
51TL	Time delay overcurrent relay. (Transformer overload protection)
63	Sudden pressure relay
67N[3]	AC Directional neutral overcurrent relay. (Ground fault protection of transformer wye winding internal faults)
71	Liquid Level Device
87T	Transformer differential relay (Fault protection for transformer internal faults)
87TN	Transformer ground differential relay (Ground fault protection of transformer wye winding internal faults)

Notes:
1. Devices 50G, 50N/51N, 50NY/51NY are alternatives.
2. Device 50GD is an alternative to 50ND/51ND.
3. Device 67N is an alternative to 87TN.

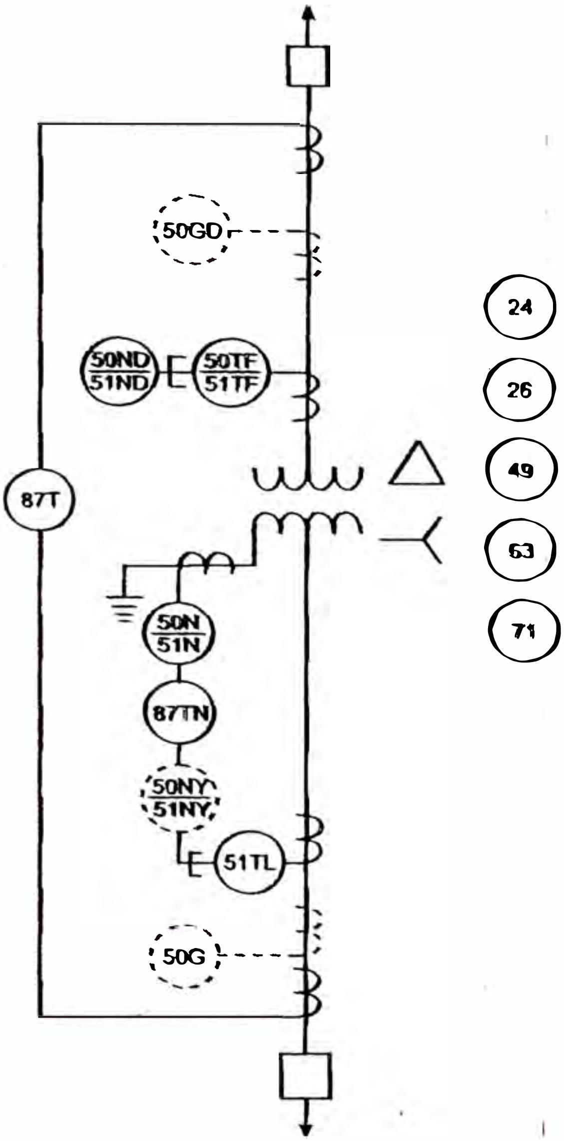


Fig. 1E. Electrical protection one-line. Protection alternatives.

2.1.2.9 Test and maintain monitoring and electrical protective devices (fuses, circuit breakers and relays) in accordance with Data Sheet 5-19, *Switchgear and Circuit Breakers*, and Data Sheet 5-20, *Electrical Testing*. All the components of the protection systems should be inspected and maintained according to their manufacturer's instructions and the recommendations of the transformer supplier.

2.1.2.10 The cause of protective relay operation should be determined before action is taken to reclose the transformer onto the electrical system. Many failures after reclosure following relay operation have been reported. Unsuccessful reclosure leads to further damage and destruction of the evidence of the cause of the relay operation.

2.1.2.11 Provide transient overvoltage ("surge") protection in accordance with Data Sheet 5-11, *Lightning and Surge Protection for Electrical Systems.*

2.1.2.12 A sound and consistent maintenance program should be established. This program should follow the specific instructions of the manufacturer of the transformer, experience and guidelines of this data sheet. The importance, criticality, physical environment and operating conditions of the transformer should be considered to establish an effective schedule.

2.2 Indoor Transformers

The following protection recommendations are based on whether the transformer is FM Approved or equivalent, the type of insulating liquid, the type of transformer and the electrical protection provided. Network transformers are considered separately from other types of transformers. A network transformer can be energized from either primary or secondary winding. The failure rates for network transformers are higher than for other types because the secondary electrical protection is not adequate.

2.2.1 Construction and Location

2.2.1.1 General

2.2.1.1.1 Indoor transformers should be located a minimum of 3 ft (0.9 m) from building walls.

2.2.1.1.2 Containment systems should be provided for liquid insulated transformers. Where transformers are located in main plant areas, curbing should be provided. Where located in a room, the room should be capable of containing the volume of liquid in the largest transformer.

2.2.1.1.3 Where nonthermal damage could occur to the occupancy liquid insulated transformers should be relocated to a room not exposing the occupancy or the room should be provided with a designed mechanical ventilation system. Power for the ventilation system should be supplied from an emergency power supply. The room construction should have a fire resistance rating specified in the following applicable sections. If a fire resistance rating is not specified, the room should be of noncombustible construction.

2.2.1.1.4 Provide ionization type smoke detection/alarms in electrical rooms to sound at a constantly attended location regardless of any automatic sprinkler protection or heat detection that may exist. Response should include notification of personnel capable of de-energizing the electrical equipment. The presence or absence of smoke detectors does not change the need for sprinklers. Smoke detection spacing should be accordance with Data Sheet 5-48, *Automatic Fire Detection.*

2.2.1.1.5 Develop a prefire plan for fire and electrical response. Electrical personnel should be capable of responding at the same time as fire fighting personnel and be able to de-energize equipment so there will be no delay in fire fighting activities. An upstream (high side) breaker located outside the electrical room accessible during emergencies may be needed to accomplish this.

2.2.1.2 Liquid Insulated Network Transformers

2.2.1.2.1 Transformers should preferably be FM Approved or equivalent (see Section 3.1.1.2, *FM Approved and Equivalent Transformers.)*

2.2.1.2.2 Transformers should be located within a room of fire resistant construction and/or protection. The fire resistance of the construction depends on the quality of insulating fluid in the largest transformer. Transformer rooms should be located on the outside wall were possible:

a) A fire resistance rating of 3 hours; or

b) A fire resistance rating of 1 hour, and provided with automatic sprinkler protection or an FM Approved gaseous agent suppression system, or a water mist system FM Approved for machinery spaces. If automatic sprinklers are used, a discharge density of 0.30 gpm/ft^2 (15 mm/min) should be provided over the area of the room.

2.2.1.2.3 Transformer rooms should be located on an outside wall where possible.

2.2.1.3 Liquid Insulated Transformers (Except Network)

2.2.1.3.1 Less Flammable Liquid Insulated Transformers

2.2.1.3.1.1 Transformers should be FM Approved or equivalent (see Section 3.1.1.2) or the following should be done:

- Location within a room with a fire resistance rating of one hour; or
- Automatic sprinklers should be provided over the transformer and for 20 ft (6.1 m) beyond. The design discharge density should be 0.20 gpm/ft^2 (10 mm/min).

2.2.1.3.2 Oil Insulated Transformers

Transformers should be located within a room of fire resistant construction. The fire resistance of the construction depends on the quantity of insulating liquid in the largest transformer. Transformer rooms should be located on an outside wall of the building where possible.

2.2.1.3.2.1. For 100 gal (0.38 m^3) or less, the fire resistance rating of the room should be one hour.

2.2.1.3.2.2 For more than 100 gal (0.38 m^3), one of the following methods should be used:

a) Location within a room with a fire resistance rating of 3 hours.

b) Location within a room of one-hour fire resistance and provided with automatic sprinkler protection or an FM Approved gaseous agent suppression system, or a water mist system FM Approved for machinery spaces. If automatic sprinklers are used, a discharge density of 0.30 gpm/ft^2 (15 mm/min) should be provided over the area of the room.

2.2.1.3.2.3 For multiple transformers in the same room, the room should be of 3-hour fire rated construction and one of the following protection methods should be used:

a) Subdivide the room so that transformers are in separate fire areas using construction with a 3-hour fire resistance rating.

b) Provide automatic sprinkler protection, an FM Approved gaseous agent suppression system, or a water mist system FM Approved for machinery spaces. If automatic sprinklers are used, a discharge density of 0.30 gpm/ft^2 (15 mm/min) should be provided over the room area (see Fig. 2).

2.2.1.3.3 Dry-Type Transformers

2.2.1.3.3.1 If dry-type transformers are located outside an electrical room they should be separated from combustible material by distance or barriers to prevent ignition of the combustible material or exposure to the transformer.

The separation distance should be 5 ft (1.5 m) horizontally and 10 ft (3.0 m) vertically; or

A barrier of noncombustible construction should be provided.

2.2.1.3.3.2 Air-cooled transformers should be located in a pressurized room where exposed to dusty or corrosive atmospheres. Cooling air for the transformer should be filtered and free of corrosive contaminants.

2.3 Outdoor Transformers

The following protection recommendations are based on whether the transformer is FM Approved or equivalent, and the volume and type of insulating liquid used. Outdoor transformers may be located on or adjacent to buildings as often happens with generating station transformers and distribution transformers at manufacturing plants. They may also be located in remote areas such as substations.

2.3.1 Construction and Location

2.3.1.1 Exposure Protection

Buildings or equipment exposed by transformers should be protected by separation, a fire barrier or a water spray system on the transformers.

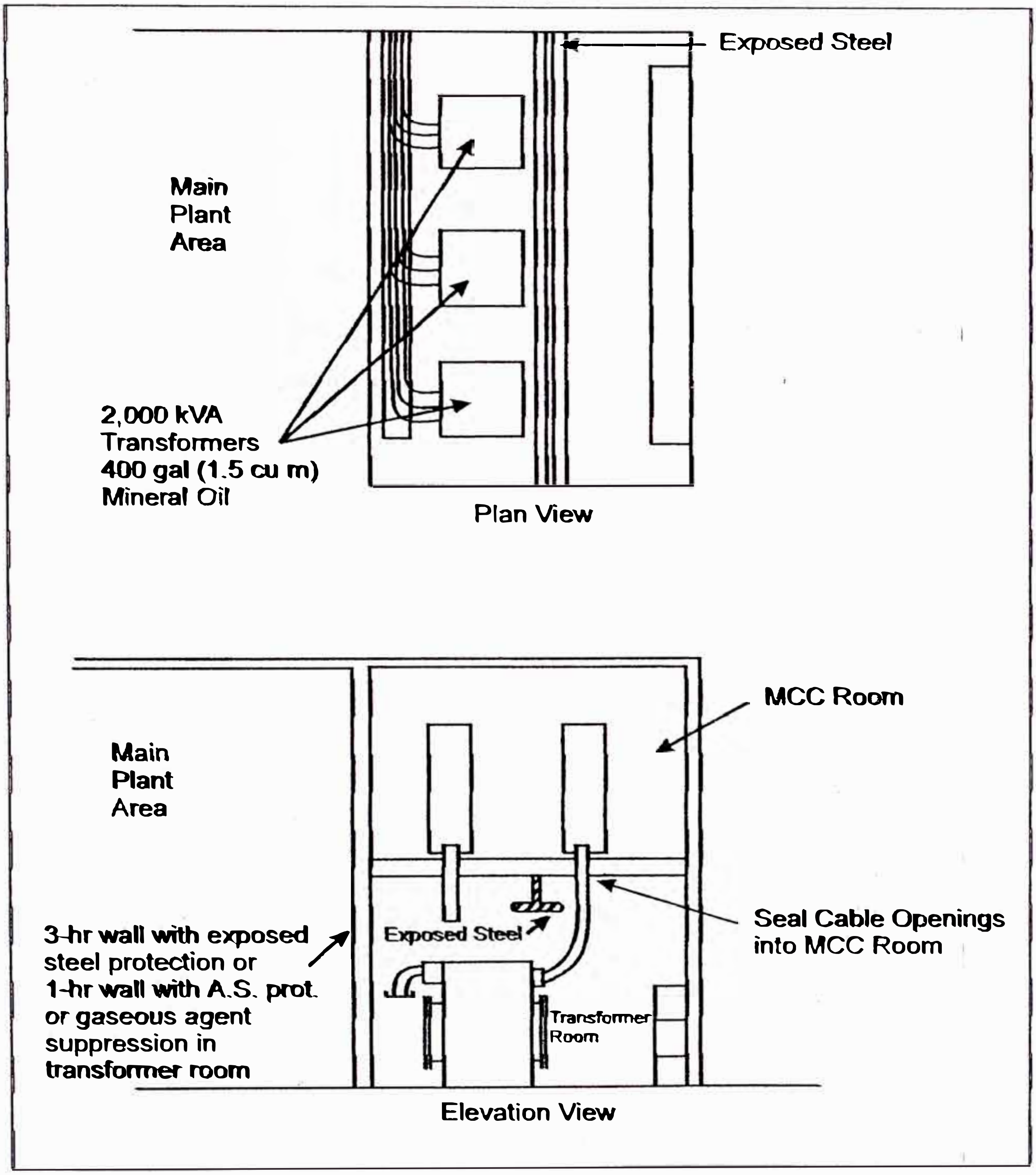


Fig. 2. Plan and elevation view of transformer room and MCC room containing three mineral oil insulated transformers.

2.3.1.1.1 *Separation Distance*

2.3.1.1.1.1 The separation distance between buildings and transformers should be as indicated in Table 2a. Horizontal distance is measured from the transformer if an FM Approved less flammable fluid is used. Horizontal distance is also measured from the transformer where unapproved fluids or mineral oil filled transformers less than 500 gal (1.9 m^3) are used and the ground slopes away from the transformer. If the transformer contains an unapproved fluid or mineral oil of 500 gal (1.9 m^3) or more the distance is measured from the dike (see Fig. 3).

2.3.1.1.1.2 The separation distance between other equipment (including adjacent transformers) should be as indicated in Table 2b.

Table 2a. Separation Distance Between Outdoor Liquid Insulated Transformers and Buildings

Liquid	FM Approved Transformer or Equivalent	Liquid Volume, gal (m^3)	Horizontal Distance (1)			Vertical Distance ft (m)
			Two Hour Fire Resistant Construction, ft (m)	Non-combustible Construction, ft (m)	Combustible Construction, ft (m)	
Less Flammable (FM Approved Fluid)	Yes	N/A	3 (0.9)			5 (1.5)
	No	≤10,000 (38) >10,000 (38)	5 (1.5) 15 (4.6)		25 (7.6) 50 (15.2)	25 (7.6) 50 (15.2)
Mineral Oil or (unapproved fluid)	N/A	<500 (1.9) 500-5,000 (1.9-19) >5,000 (19)	5 (1.5) 15 (4.6) 25 (7.6)	15 (4.6) 25 (7.6) 50 (15.2)	25 (7.6) 50 (15.2) 100 (30.5)	25 (7.6) 50 (15.2) 100 (30.5)

(1) All transformer components must be accessible for inspection and maintenance.

Table 2b. Outdoor Fluid Insulated Transformers Equipment Separation Distance (1)

Liquid	FM Approved Transformer or Equivalent	Fluid Volume, gal (m^3)	Distance, ft (m)
Less Flammable (FM Approved Fluid)	Yes	N/A	3 (0.9)
	No	≤10,000 (38) >10,000 (38)	5 (1.5) 25 (7.6)
Mineral Oil or (unapproved fluid)	N/A	<500 (1.9) 500-5,000 (1.9-19) >5,000 (19)	5 (1.5) 25 (7.6) 50 (15.2)

(1) All transformer components must be accessible for inspection and maintenance.

2.3.1.1.2 *Fire Barriers*

2.3.1.1.2.1 Buildings

2.3.1.1.2.1.1 Where building walls are used for protection, the exposed wall should extend the horizontal and vertical distances from the dike or transformer specified in Table 2a.

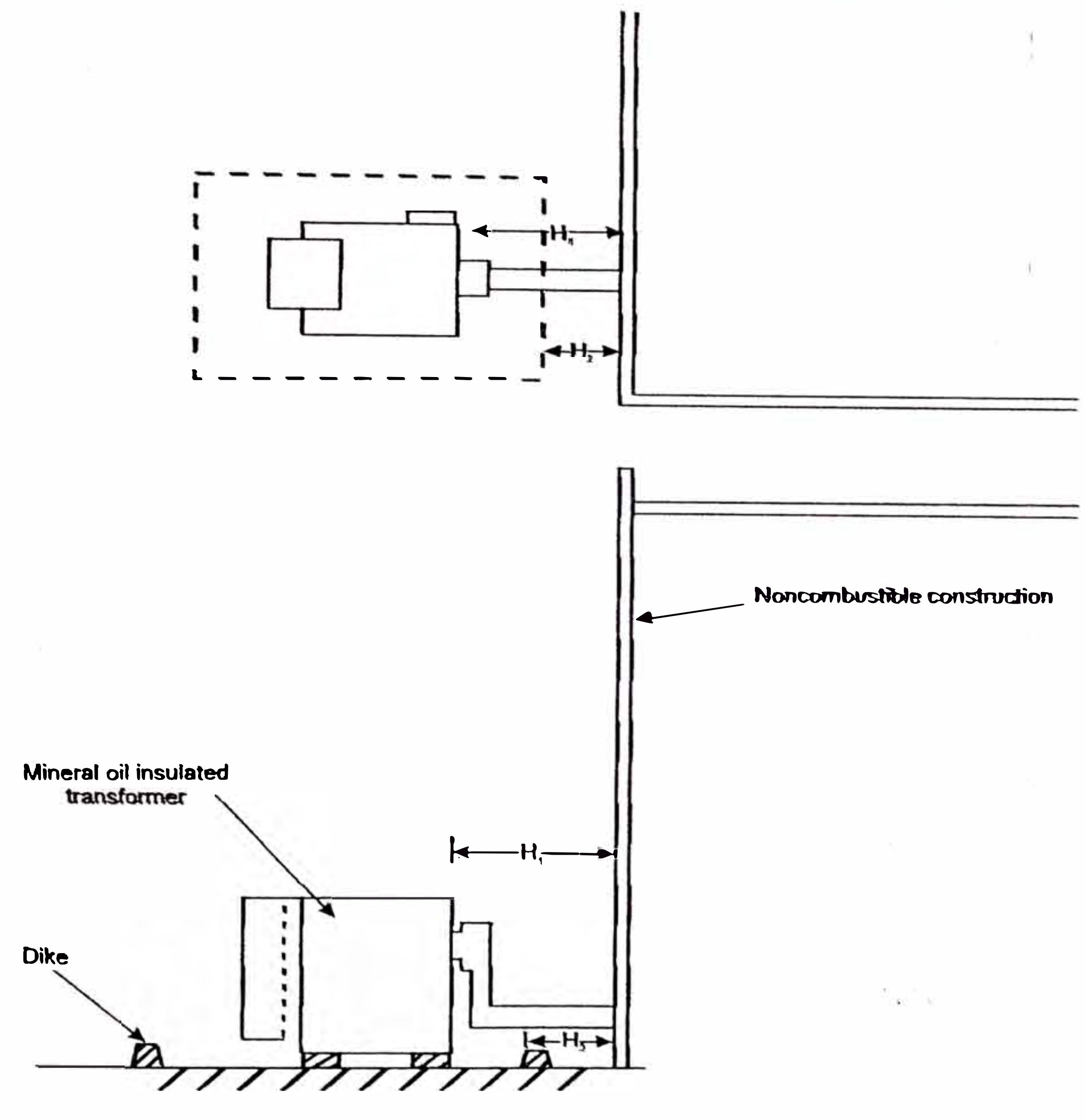
2.3.1.1.2.1.2 Roofs exposed by mineral oil insulated transformers should be Class A rated for the exposed area. The exposed area is considered to be the following:

a) 15 ft (4.6 m) from a transformer containing 1,000 to 5,000 gal (3.8 to 19 m^3) of mineral oil where roofs are less than 25 ft (7.76 m) high.

b) 25 ft (7.6 m) from a transformer containing in excess of 5,000 gal (19 m^3), where roofs are less than 50 ft high.

2.3.1.1.2.2 Equipment

2.3.1.1.2.2.1 For equipment protection, barriers should extend 1 ft (0.3 m) vertically and 2 ft (0.6 m) horizontally beyond transformer components that could be pressurized as the result of an electrical fault. This would typically include bushings, pressure relief vents, radiators, tap changer enclosures, etc.



H1 = Transformer less than 500 gal. and where ground slopes away from building dike not needed. Horizontal distance is measured from transformer to building.
H2 = Where ground is flat or slopes to building dike should be provided. Horizontal distance is measured from dike to building.

See table 2A for horizontal distances

Fig. 3. Separation between liquid insulated transformer and building.

2.3.1.1.2.2.2 Barriers should be of concrete block or reinforced concrete construction adequate for 2-hour fire resistance.

2.3.1.2 Containment

2.3.1.2.1 General

2.3.1.2.1.1 Provide a containment system for transformers under the following conditions:

a) Mineral oil filled transformers where a release of fluid would expose buildings.

b) Mineral oil filled transfonners containing more than 500 gal (1.9 m^3) of mineral oil.

c) FM Approved less flammable fluid filled transformers containing more than 1320 gal (5 m^3) of fluid.

d) FM Approved less flammable fluid filled transformers where the fluid is certified as a biodegradable fluid by the government environmental protection agency and where a release of fluid would not expose navigable waterways (see Appendix A for definition). The transformer should be properly labeled. Transformers containing more than 2640 gal (10 m^3) of fluid should be provided with containment.

2.3.1.2.1.2 The containment system should be large enough for the volume of oil in the largest transformer and the water from a 10-min discharge of the water spray system if provided. If there are three or more transformers, it should be assumed that the fire will occur in the middle transformer and the water spray systems on adjacent transformers will operate.

2.3.1.2.1.3 The containment system should consist of a pit or a diked area and a drainage system for removal of rainwater. The pit should be protected as described in 2.3.1.2.2 and 3 if the transformer is mineral oil insulated. It may be unprotected if the transformer contains an FM Approved less flammable fluid.

2.3.1.2.1.4 The pit or diked area should be sized to contain the contents of the largest transformer. The area of the pit should extend as follows:

a) For transformers containing 1,000 gal (3.8 m^3) or less, the area of the pit should extend 3 ft (0.9 m) beyond oil containing components where curbing is provided and 5 ft (1.5 m) beyond oil containing components where curbing is not provided.

b) For transformers containing more than 1,000 gal (3.8 m^3), the area of the pit should extend 5 ft (1.5 m) beyond oil containing components where curbing is provided and 8 ft (2.4 m) beyond oil containing components where curbing is not provided.

2.3.1.2.2 Rock-Filled Pits

2.3.1.2.2.1 Where rock-filled pits are used, the rock should be loosened and turned as necessary to prevent filling of void spaces by dirt, dust or silt. The frequency is dependent on area of the country and location near manufacturing facilities which generate dust or flyash.

2.3.1.2.3 Open Pits

2.3.1.2.3.1 Where an open pit is used, one of the following forms of protection should be provided:

a) Automatic sprinkler or water spray protection should be provided for the pit area designed to a discharge density of 0.30 gal/min ft^2 (15 mm/min) over the area of the pit; or

b) A 12-in (30 cm) thick layer of rock located on steel grating should be provided at the top of the pit. The rock used should be 1.5 in. (3.8 cm) washed and uniformly sized rock, (Size No 5, ASTM D448 *Standard Classification for Sizes of Aggregate for Road and Bridge Construction*). (See Fig. 4.)

2.3.1.3 Roof-Mounted Transformer Installations

2.3.1.3.1 Containment systems should be provided for roof-mounted transformers.

a) For transformers with 500 gal (1.9 m^3) or less insulating liquid, the containment system may be a welded steel pan or curbed concrete mat with capacity large enough to handle the liquid in the largest transformer.

b) For mineral oil insulated transformers with more than 500 gal (1.9 m^3) liquid capacity, containment should be rock-filled or of the open pit design with protection as recommended in Section 2.3.1.2.2 and 2.3.1.2.3. For FM Approved less flammable fluid insulated transformers an open containment may be used.

c) Class A roof construction should be used for the horizontal distance from the transformer specified for noncombustible construction in Table 2a.

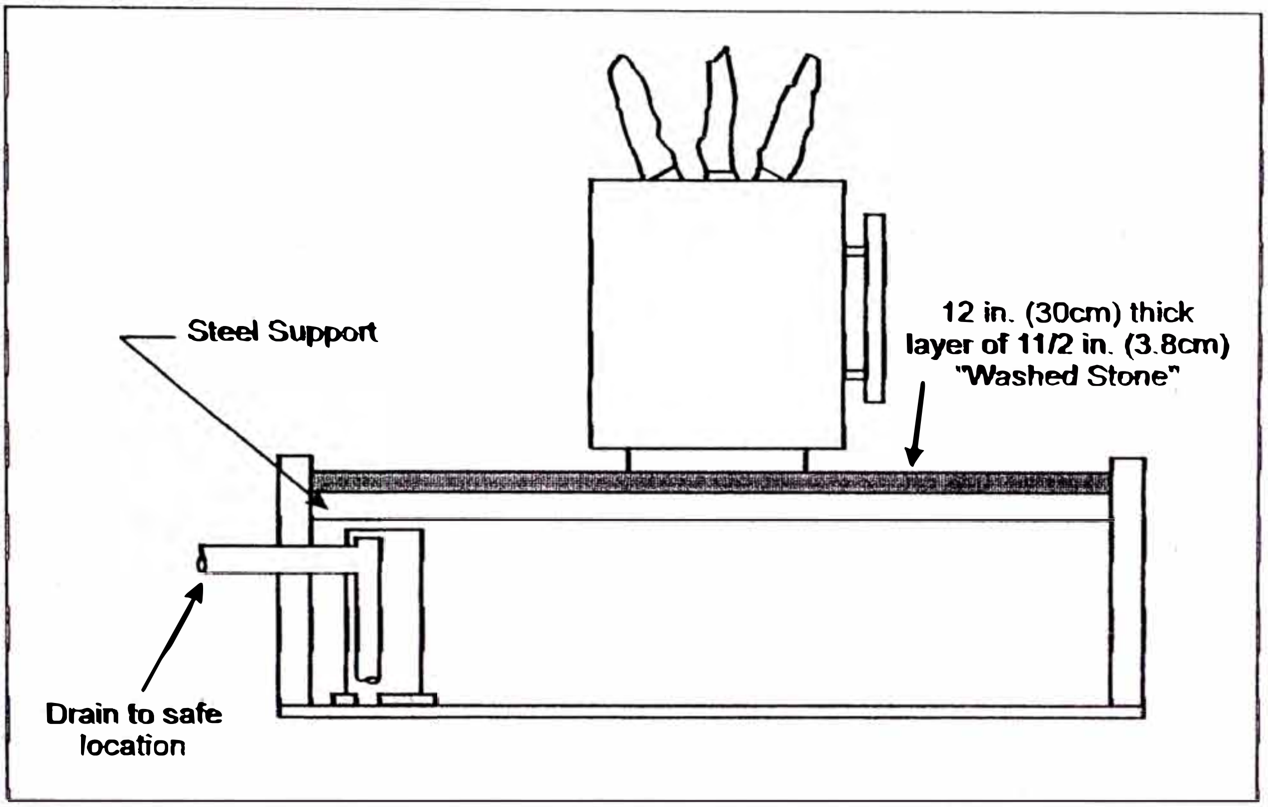


Fig. 4. Open-pit containment system.

2.3.1.3.2 The containment system should be drained to a safe location acceptable to the authority having jurisdiction.

2.3.1.3.3 Adjacent buildings and other equipment should be protected in accordance with Section 2.3.1.1.

2.3.2 *Protection*

2.3.2.1 Water Spray Exposure Protection

2.3.2.1.1 Buildings

2.3.2.1.1.1 If water spray or automatic sprinkler protection is used for building protection, a discharge density of 0.20 gpm/ft^2 (8 mm/min) should be used over the exposed surface.

2.3.2.1.1.2 The water supply should be adequate for 2 hours and should include a hose stream demand of 500 gpm (1900 l/min).

2.3.2.1.2 Equipment

2.3.2.1.2.1 For multiple transformer installations the water spray system should be designed based on simultaneous operation of the water spray systems for the adjacent transformers.

2.3.2.1.2.2 The water spray system should be designed to provide a density of 0.25 gal/min ft² (10 mm/min) over transformer surfaces, except areas under the transformer in accordance with Data Sheet 4-1N, *Water Spray Fixed Systems*.

2.3.2.1.2.3 Where the ground around the transformer is nonabsorbing, water spray should be provided at a density of 0.15 gal/min ft² (6 mm/min) for the diked area or for a distance of 10 ft (3 m) from the transformer in all directions.

2.3.2.1.2.4 Components of the water spray system, such as piping, spray nozzles, etc. should be a minimum of 18 in. (45.7 cm) from the transformer.

2.3.2.1.2.5 Piping should not pass over the top of the transformer or be exposed by tank relief vents.

2.3.2.1.2.6 Water spray nozzles should not be directed at bushings.

2.3.2.1.2.7 The water supply should be adequate for 1 hour and include a hose stream demand of 250 gpm (950 l/min).

2.3.2.2 Hydrant Protection

2.3.2.2.1 Provide hydrant protection where transformers present an exposure to buildings and equipment. Nozzles FM Approved by FM Approvals for use on electrical equipment are preferred. Nozzles that produce a spray angle of 30 to 90 degrees without passing through a solid stream are acceptable. If solid hose streams are used with equipment up to 138 kV, the minimum approach distance should be 20 ft (6.1 m) for 1-½ in. nozzles and 30 ft (9.1 m) for 2-½ in. (6.4 cm) nozzles. Tests have not been conducted on equipment with voltages above 138 kV and solid hose streams should not be used until this equipment is de-energized.

2.4 Transformer Production Test Areas

2.4.1 Protection

2.4.1.1 Automatic sprinkler protection should be installed at ceiling level throughout the test area. The discharge density should be a minimum of 0.20 gpm/ft² (8 mm/min) for the following: a) 3,000 ft² (278.7 m²) for wet pipe systems with 286°F (141°C) rated heads; b) 4,000 ft² (371.6 m²) for wet systems with 165°F (74°C) heads; c) 5,000 ft² (464.5 m²) for dry systems with 286°F (141°C) heads; d) 6,000 ft² (557.4 m²) for dry systems with 165°F (74°C) heads.

2.4.1.2 At least 6 in. (15 cm) high curbs should be provided around the test area with the curbed area drained to a safe location acceptable to the authority having jurisdiction.

2.4.1.3 A standpipe with 1-½ in. (40 mm) hose connections should be provided such that all areas can be reached with at least one hose stream.

2.5 Transformers Insulated with Liquids Containing Polychlorinated Biphenyls (PCBs)

2.5.1 Operation and Maintenance

2.5.1.1 General

2.5.1.1.1 Transformers which have been flushed and refilled with a replacement liquid should be tested at 3 to 5 year intervals in accordance with Data Sheet 5-20, *Electrical Testing*, to verify that PCB concentrations are below 50 ppm.

2.5.1.1.2 PCB-filled and PCB-contaminated transformers containing more than 50 ppm PCBs should be replaced.

2.5.1.2 Operation, Maintenance, and Fire Protection

Pending replacement of PCB-filled and PCB-contaminated transformers, the following should be done:

2.5.1.2.1 An emergency response plan to handle a PCB spill should be developed. The plan should be in writing and should include:

- Availability of an emergency power supply

Telephone numbers for salvage and emergency, critical plant personnel, a PCB disposal firm, and the local FM Global office.

Telephone numbers of appropriate authorities. In the United States this includes the National Spill Response Center, and the nearest EPA Office.

2.5.1.2.2 A visual inspection should be performed for transformers in use or stored for reuse on a *monthly* frequency if the transformer is accessible without shutdown of the transformer, and *annually* where the transformer cannot be inspected without shutdown.

2.5.1.2.3 Damaged or leaking areas should be repaired.

2.5.1.2.4 Floor drains exposed to a PCB spill should be sealed except drains to an oil containment system.

2.5.1.3 PCB-Insulated Transformer Replacement

2.5.1.3.1 Drain PCB-contaminated liquid from transformers containing more than 100 gal (0.38 m^3) before movement.

2.5.1.3.2 Drums containing liquid PCB should be packed within a larger outer drum with absorbent material between the two drums.

2.5.1.3.3 A pre-emergency plan should be developed before moving PCB-filled equipment or containers to minimize exposure to plant areas. The plan should include verification that spill containment equipment such as plastic sheeting, oil absorbent materials and empty drums are available.

2.5.1.3.4 Drums containing PCBs should be removed from main plant areas and disposed of as soon as possible. If drums are stored on-site, they should be stored in detached low value buildings. The following precautions should be taken:

- The drums should be stored in a room of noncombustible construction with noncombustible occupancy.
- Floor areas should be provided with a minimum 6 in. (15.2 cm) high curb. The volume of the curbed area should be capable of containing either twice the volume of the largest container or 25% of the volume of the PCB containers in the room, whichever is larger.
- There should be no drains within the curbed area.
- Floor and curbing surface area should be constructed of impervious materials, such as concrete.

2.5.2 Construction and Location

2.5.2.1 Where transformers are in open plant areas the following should be done:

- Provide a curbed area around each transformer or bank of transformers sufficient to contain liquid from the largest transformer. Isolate PCB-contaminated transformers from hazardous processes or areas of combustible storage by means of one of the following:

  a) A one-hour fire rated barrier

  b) A minimum 15 ft (5 m) separation distance free of combustibles.

2.5.2.2 Where transformers are within rooms or vaults the following should be done:

- Seal wall penetrations
- Exhaust air directly to the outside
- Keep the room free of combustibles

3.0 SUPPORT FOR RECOMMENDATIONS

3.1 Discussion

3.1.1 FM Approved and Equivalent Transformers

Approval is intended for liquid-filled transformers rated at 5 to 10,000 kVA. If a transformer is FM Approved, fire frequency is considered reduced sufficiently such that fire protection considerations are not necessary. The FM Approval program considers the transformer as a system that includes evaluation of the fire properties of the liquid, the ability of the tank and transformer components to withstand the pressure generated by a low level electrical fault, and the ability of electrical protection to clear a fault before tank rupture. The conditions of Approval are as follows:

1. Tank design strength to prevent tank rupture under low energy fault conditions.

2. A pressure relief device to relieve pressure if a low current fault occurs until the fault can be cleared by electrical protection described in Item 3 below.

3. Electrical protection to clear sustained low current faults. This protection could be in the form of a ground fault relay and sudden pressure relay, or other devices of equivalent reliability.

4. Electrical protection to clear high current faults. This protection is based on the kVA rating of the transformer and is intended to electrically isolate the transformer rapidly enough to prevent pressure increase to greater than half the tank burst pressure.

5. FM Approved transformer fluids have a fire point of 572°F (300°C) or more.

For FM Approved network transformers, secondary side electrical protection is needed in addition to the above. This protection could be in the form of ground fault detection or other technology of demonstrated equivalence. This device should trip the high-side disconnect devices of the transformer experiencing the fault and other paralleled transformers in the network.

An equivalent transformer is one with a UL listing per NEC Section 450-23 and electrical protection to clear sustained low current faults. A UL listed transformer per NEC Section 450-23 will include the protection features described above except for Item 3. If electrical protection to clear sustained low current faults is provided, the transformer should be equivalent to an FM Approved transformer.

3.1.2 Transformer Electrical Protection

The purpose for providing transformer electrical protection is to:

a) Separate the transformer from the remainder of the system to allow the system to continue to operate.

b) Limit damage to the transformer.

c) Limit damage to the rest of the system.

d) Minimize the possibility of fire.

e) Minimize hazards to personnel.

The cost of transformer repairs and the associated downtime may be expensive. High speed sensitive transformer protection can reduce transformer and system damage and therefore repair costs. There is no single way to protect transformers. Various protection alternatives need to be investigated to determine the best and most cost effective scheme considering protective device speed, sensitivity and selectivity. Backup protection should also be considered since failure of a single protective device or breaker could cause even more extensive damage to the transformer. The selected protection should minimize:

a) Cost of repairing or replacing transformer damage.

b) Cost of lost production.

c) Cost of repairing/replacing adjacent equipment/property.

d) Adverse effects on the balance of system.

There are several devices available that can be used to detect faults in the transformer and guard against the associated hazards.

3.1.2.1 Mechanical Detection of Faults

There are several devices that are used to detect liquid level and tank pressure.

3.1.2.1.1 Liquid Level Gauge, Device 71[1]

The liquid level gauge measures the level of the insulating liquid within the transformer tank. The gauge is calibrated against a predetermined liquid level at 25°C (77°F). A low liquid level could indicate a loss of liquid. Low liquid level can result in overheating, insulation failure or flashover. The liquid level gauge should be provided with alarm contacts. The alarm should sound to an attended location prior to the liquid level lowering to the point where the transformer is endangered.

3.1.2.1.2 Pressure-vacuum Gauge

The pressure-vacuum gauge indicates the difference between the transformer internal pressure and atmospheric. The transformer tank internal gas pressure is related to the thermal expansion of the transformer liquid and varies with the temperature. The temperature of the liquid is a function of the ambient temperature and transformer loading. The pressure-vacuum gauge should be tested for proper operation if its indication remains constant for a long period under various temperature and loading conditions. The pressure-vacuum gauge should be set to alarm before a tank rupture or deformation can occur. It is always better to have a positive pressure (3-5 psi) to prevent possible moisture and other contaminants from entering the tank.

3.1.2.1.3 Pressure Relief Device

This device should be provided on all liquid-filled transformers to prevent overpressurization and tank rupture. When the transformer tank's internal pressure exceeds the pressure relief device set pressure, the device opens, allowing the gas and/or liquid to be released. On large transformers the device should be provided with an alarm contact and initiate an alarm at an attended location. The pressure relief device is self resetting and self sealing. The pressure relief device should be tested to ensure proper operation. The device is normally mounted on top of the transformer tank and is provided with a visual operation indicator.

The operation indicator must be manually reset after the pressure relief device operates.

3.1.2.1.4 Gas Accumulation and Sudden Pressure

There are two basic mechanical methods for detecting transformer faults: gas accumulation and oil or gas pressure increase. Gas accumulation results from decomposition of insulation or oil. Sudden pressure increases are caused by internal and through-faults. The sudden pressure from the through-fault is caused by the electromagnetic forces moving the core/core assembly. The sudden pressure from internal faults is caused by the electromagnetic forces and oil vaporization from the arc energy. For internal faults these relays are more sensitive than relays using electrical quantities.

3.1.2.1.4.1 Gas Detector Relay, Device 63

The gas detector relay is applicable only on transformers having conservator-type liquid preservation/sealing systems. It detects gas evolution from arcs and overheating. The relay alarms when 200 cc of gas has accumulated in its chamber. A gas sample should then be removed for analysis.

3.1.2.1.4.2 Sudden Gas Pressure Relay, Device 63

The sudden gas pressure relay is applicable to gas-cushioned oil-immersed transformers. The relay is mounted in the region of the gas space. The relay can detect low or high energy arcs. The inert gas above the insulating liquid transmits the pressure wave to the relay. For high energy arcs the relay operates on a gas pressure rate-of-rise. The speed of the relay is directly proportional to the pressure rate-of-rise. High energy internal faults produce a large quantity of gas with a resultant high pressure rate-of-rise. The high pressure rate of rise results in fast relay operation (50-100 ms). Low energy arcs produce a smaller pressure rate of rise. The lower rate-of-rise results in slower relay operating times (500-1000 ms).

The most recent design of this relay uses two chambers, two control bellows, and a single sensing bellow. All three bellows have a common interconnecting silicone passage. Dissimilar expansion rates of the two control bellows initiates relay operation.

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[1] *Device numbers are listed in Table 1.*

The relay should be mounted in accordance with the transformer manufacturer's instructions. An auxiliary relay (63X) should be provided to seal in the sudden pressure relay contacts and to prevent false operations. With the above precautions taken into consideration, the reliability of the modern sudden pressure relay is very good. The relay should be connected to trip the transformer high and low side circuit breakers.

3.1.2.1.4.3 Sudden Oil Pressure Relay, Device 63

This relay is applicable to all oil-immersed transformers and is mounted on the tank below the minimum liquid level. It detects internal faults generating rapid rises in oil pressure. The rapid rise in oil pressure is transmitted to the silicone liquid in the relay by way of the transformer oil and the relay closes its contacts. The most recent design of this relay is similar to that described for the sudden gas pressure relay. The same installation precautions as for the sudden gas pressure relay need to be considered. The relay should be connected to trip.

3.1.2.1.4.4 Gas Accumulator Relay (Buchholz Relay), Device 63

The gas accumulator relay is applicable only to transformers with conservator tanks without gas space in the main tank. It is a combination of a gas detector relay and a sudden oil pressure relay. The relay is installed in the pipe running from the main tank to the conservator tank. It can detect gas volume generated in its gas detector mode or high velocity oil flow (large faults) in the sudden oil pressure mode. The gas detector portion of the relay is normally used to alarm and the sudden pressure part is used to trip.

Note: Not all these devices can be used in a given type of transformer, although generically they appear to be compatible. This is due to physical construction of a given transformer, oil pump location, cover construction, and liquid preservation system. The transformer manufacturer should be consulted for the applicability of a specific gas and/or sudden pressure relay and for its mounting location on the specific transformer.

3.1.2.2 Thermal Detection of Abnormalities

Overheating shortens the life of transformer insulation. Insulation deterioration is directly proportional to the duration and magnitude of overtemperature. Severe overtemperature may result in rapid or immediate insulation failure. Transformer overheating may be caused by:

1. High ambient temperature (greater than 30°C [86°F])

2. Failure of cooling system

3. Overloading

4. Through-faults not cleared within transformer's through-fault capability characteristic time.

5. Abnormal system conditions (high voltage, low frequency, overexcitation, volts/hertz, nonlinear loads, phase unbalance.)

Continuous monitoring of transformer temperature and protection against overtemperature is imperative and is attained by the following methods.

3.1.2.2.1 Hot-spot Temperature, Device 49.

The hot-spot temperature gauge indicates the hottest-spot temperature of the transformer. The location of the hottest spot of the transformer is monitored by simulation methods, and appropriate warnings or trips are triggered when necessary. Hot-spot temperature can be simulated by thermal relays and replica relays. The thermal relay is responsive to both top-oil temperature and to the direct heating effect of load current. A current transformer (CT) supplies current proportional to winding current to the thermometer bulb heating coil mounted in the top oil. The thermometer bulb measures the oil temperature with the heat effect of loading and therefore tracks the temperature which the hot spot of the winding attains during operation.

The replica relay, based on the Wheatstone Bridge principle, measures the resistance of resistance temperature detectors (RTD) immersed in the oil. Current transformers supply current, proportional to winding current, to a heating coil mounted beside the RTD. The heating coil heats the oil around the RTD, simulating a hot spot. The RTD's resistance varies with this oil temperature. The RTD forms the balance leg of the bridge circuit in the relay. The relay is therefore responsive to the transformer hot spot temperature. Temperatures from several locations within the transformer can be monitored with this scheme.

3.1.2.2.2 Top-oil Temperature, Device 26

The liquid temperature indicator measures the insulating liquid temperature above the core/coil assembly. The temperature indicator is reflective of the transformer loading only to the extent that loading affects the liquid temperature rise above ambient. The top-oil temperature changes very slowly to changes in load because the liquid thermal time constant is much greater than the winding time constant. During periods of rapid load increases or decreases, the liquid temperature reading may lag behind the actual temperature of the conductors.

3.1.2.2.3 Fuses or Overcurrent Relays, Device 51

These devices, under certain conditions, may provide some degree of thermal protection. These devices are mainly used to provide short circuit protection. Description of these devices for both thermal and fault protection can be found in Section 3.1.2, Transformer Electrical Protection.

3.1.2.2.4 Overexcitation Protection, Device 24

Overexcitation protection for transformers is needed for direct-connected unit generator step-up transformers. The protection prevents overheating the transformer and unlaminated metal parts, with resultant thermal damage to adjacent insulation from excessive excitation current. Overexcitation relays (volts/Hz) provide warnings and/or trip functions mainly for directly-connected generator transformers subjected to wide ranges of frequency during the acceleration and deceleration of turbine-generator sets. The volts per hertz ratio should be less than 1.1 times the ratio of transformer rated voltage to rated frequency.

Overexcitation occurs when the ratio of volts/hertz exceeds 110% at the transformer's primary terminal. For a generator step-up transformer this would be the low voltage side. Overexcitation can occur during startup and shutdown of the generator, especially if the machine's voltage regulator is in a manual mode. This protection may be provided as part of the excitation control of the generator or by a separate Volts per Hertz Relay, Device 24.

Separate overexcitation protection of unit connected generator step-up transformer is required if the protection is not built into the generator excitation system. A separate volts per hertz should be provided if the overexcitation protection supplied by the generator manufacturer is bypassed when the voltage regulator is in manual mode and this is the normal method used to start and stop the machine. The transformer manufacturer should be contacted for proper coordination with either device and the transformer overexcitation limits.

3.1.2.3 Electrical Detection of Overloads and Faults

Overloads and faults can be electrically detected by fuses and protective relays. To provide proper protection, these devices must be able to distinguish between an acceptable overload within the transformer's capability and internal faults. The protective device must also be able to detect harmful overloads and through-faults that are not cleared by downstream protection. The electrical protection system must be able to detect all types of faults (three-phase, phase-to-phase, and phase-to-ground faults). Generally, several different devices are needed for the various fault conditions/types and overload conditions. Transformer overload protection should be applied on the load side of the transformer. Separate transformer protection for phase and ground faults should be provided. Transformers that are connected delta-wye require two ground fault schemes, one for the delta winding and one for the wye winding.

3.1.2.3.1 Coordination of Protective Devices

The selection of appropriate fuses and/or protective relays should be the result of an engineering study that has considered the coordination of all other protective devices and the electrical characteristics of the system to be protected.

The primary-phase protective device must be set above the transformer magnetizing inrush current and normal overload. This requirement reduces the degree of protection provided for the transformer. The protective devices at transformer loads should be selected to prevent loading of the transformers beyond the transformer short time overload capability. The transformer manufacturer can be consulted to determine the overload capability of specific transformers. The time-current characteristic of the transformer primary protective devices should coordinate with other overcurrent devices on both the primary and secondary-side of the transformer.

The primary protective device should protect the transformer against damage from thermal and mechanical stresses resulting from a transformer secondary-side fault. The primary protective device time-current curve should coordinate and be less than the transformer through-fault withstand capability curve. (See ANSI Standard C57.109, Transformer Through-Fault Current Duration Guide.) This characteristic takes into consideration that the transformer damage is cumulative. The degree of transformer protection provided by the primary device for the minimum value for different types of secondary-side faults (three-phase, phase-to-phase, phase-to-ground) should be determined. The device should be selected so that it will operate fast enough to prevent transformer winding damage for minimum values of fault currents.

Electrical quantities (kV, kA, kVA, kW, kVAR, and Z) are usually expressed in per unit or percent of a reference or base value. Percent is 100 times per unit quantity. The per unit value of any quantity is the ratio of that quantity to its base value. A 2500 kVA, 13.8 kV/480 V, 5.75% delta-wye transformer base values are 2500 kVA, 13.8 kV primary voltage, 105 A primary current, 0.480 kV secondary voltage, and 3000 A secondary current. The nameplate impedance is given in percent. Its per unit value is 0.0575 pu.

For a delta-wye transformer a secondary line-to-ground fault results in primary currents on two phases of 0.58 per unit or 58% of the secondary fault current referred to the primary-side. If a 20-kA secondary-side line-to-ground fault occurred on phase "A", the primary current seen by phases "A" and "C" would be 0.58 (0.480 kV/13.8 kV) 20 kA = 0.4 kA or 400 A. A secondary phase-to-phase fault on this transformer connection results in primary currents of 1.0 per unit on one phase and 0.5 per unit on the other two phases.

For a delta-delta transformer a secondary phase-to-phase fault results in primary currents on two phases of 0.87 per unit of the secondary current. Table 3 shows the effects of the delta-wye phase shifts for various faults.

3.1.2.3.2 Fuse Protection

This method is mainly used for transformers rated less than 5000 kVA. Fuses are a simple and inexpensive means of providing overload and fault protection of transformers. The main disadvantage of using fuses is that the operation of a single fuse 1) may cause single phasing and 2) may not de-energize a fault on a three-phase system. Single phasing on a three-phase system occurs when one phase does not carry any current and the other two phases do carry current. Both conditions expose other components of the distribution system to failure. The resulting single phase service may endanger polyphase motors and other loads. Fuses should be applied in combination with load-interrupter switches to trip all three phases.

Primary-side fuses are often used for protection against source-side and internal faults. They may not be effective for load-side faults when fuses are applied on the source-side only. They are not effective in detecting secondary-side arcing ground faults. Also primary-side fuses larger than 125% of transformer rated current may not provide adequate overload protection.

Fuse selection should be based on the following factors:

1. Ampere rating. The primary fuse should have an ampere rating that provides a continuous current capability greater than the maximum expected load. This requirement may reduce the degree of protection provided by the transformer.

Table 3. Effects of Delta-Wye Phase Shifts

Fault Type	*Primary Line Current*	*Primary Winding*		*Secondary Winding*		*Secondary Line Current*
		Type	*Current*	*Type*	*Current*	
3-Phase	1.0	Δ	0.58	Δ	0.58	1.0
3-Phase	1.0	Δ	0.58	Y	1.0	1.0
Line-Line	A 0.87	Δ	AB 0.58	Δ	AB –0.58	A 0.87
	B –0.87		BC 0.29		BC 0.29	B –0.87
	C 0		CA 0.29		CA 0.29	C 0
Line-Line	A 1.0	Δ	AB 0.5	Y	A 0.87	A 0.87
	B –0.5		BC 0		B –0.87	B –0.87
	C–0.5		CA –0.5		C 0	C 0
Line-Neutral	A 0.58	Δ	AB 0	Y	A 1.0	A 1.0
	B 0		BC 0		B 0	B 0
	C –0.58		CA –0.58		C 0	C 0
					N 1.0	N 1.0

2. Withstand inrush currents. The actual time-current profile for both transformer cold and hot load pickup of the distribution system should be determined. Cold load pickup is the combined magnetizing and load inrush currents associated with re-energizing a transformer after an extended outage. Hot load pickup is the combined magnetizing and load inrush currents associated with re-energizing a transformer after a momentary service interruption. The fuse characteristic must be greater than the sum of both transformer magnetizing and cold load inrush and transformer magnetizing and hot load inrush currents of the distribution system.

3. *Interrupting rating*. The fuses' interrupting capability must be greater than the available system fault current at the point of application.

4. Transformer through-fault withstand. The primary-side fuse total clearing time-current curve should coordinate and be less than the transformer through-fault withstand capability curve. The total clearing time curve of the primary-side fuse should cross the transformer through-fault capability curve at a low level of current. The lower the intersection of the two curves, the greater the degree of protection provided by the primary-side fuse.

5. Coordinate with other protective devices. The time-current characteristic of the transformer primary-side fuse should coordinate with other overcurrent devices on both the primary and secondary side of the transformer.

A power fuse is defined per ANSI/IEEE C37.100-1981 as: "A fuse consisting of an assembly of a fuse support and a fuse unit or fuse holder which may not include the refill unit or fuse link." There are two basic types of power fuses: 1) expulsion type and 2) current limiting type.

The expulsion-type fuse is a vented fuse that extinguishes the arc via the deionization action of the gases. The gases are liberated from the lining of the interrupter chamber of the fuse. The gases are produced by the arc heat when the fusible element melts.

Expulsion-type fuses have several benefits.

1. They can be sized to provide overload protection and accommodate expected load levels.

2. They can withstand the transformer current inrush due to magnetizing and load current even when fuse is sized close to the transformer full load rating.

3. They are sensitive to both primary-side and secondary-side phase faults

4. They can coordinate with the transformer through-fault capability curve, thus providing protection against damaging overcurrents.

A current-limiting fuse is a fuse, that when melted by a current within its specified current limiting range, abruptly introduces a high arc voltage impedance to reduce the current magnitude and duration. The current-limiting fuse melts in less than one-half of a cycle and therefore can interrupt the current before it reaches its maximum value.

The benefits of a current-limiting fuse are that it limits the available fault current in its current limiting range and therefore reduces thermal and magnetic stresses on system components; and it can achieve very high interrupting ratings. The major disadvantages are: 1) it generates transient overvoltages when it functions; and a fuse with ampere ratings higher than transformer full load ratings is required since the fusible element may break due to thermal fatigue from inrush currents and loading.

3.1.2.3.3 Overcurrent Relay Protection

Overcurrent protection is used to prevent damage to transformers from overloads and from through-faults. Overcurrent relays are also normally used for protection of transformers rated below 5 MVA for internal faults and as backup protection to differential relays for larger transformers.

3.1.2.3.3.1 Time phase overcurrent relays, Device 51

Time phase overcurrent relays must be set so that they do not falsely operate on normal overload and transformer inrush current, but do protect the transformer for external faults. One way of meeting all these constraints would be to use both primary and secondary-side overcurrent relays. Through-fault and backup protection would be provided by the transformer primary-side overcurrent relay, device 51TF. The relay must be set to coordinate with both upstream and downstream protective devices, the transformer inrush characteristic and the through-fault capability curves. Inrush current is typically 8 to 12 times rated current for 0.1

seconds. Refer to Section 3.1.2.3.1, Coordination of Protective Devices, for a discussion on transformer through-fault withstand capability and per unit fault magnitudes for various transformer winding connections. Since relays normally trip all three phases of circuit breakers, single phasing will not occur, as it can with fuse protection.

Overload protection would be provided by the secondary-side overcurrent relay, device 51TL. The relay should be coordinated with both the transformer short-time overload capability and the transformer through-fault capability curves. Overload protection is typically set at 115% of the maximum acceptable overload.

3.1.2.3.3.2 Instantaneous Phase Overcurrent Relays, Device 50TF

Instantaneous phase overcurrent relays, device 50TF, provide fast tripping for severe transformer internal faults. Extensive damage to the transformer could result if only time phase overcurrent relays are used for internal fault protection. The instantaneous relay is placed on the transformer primary side and set so that it will not respond to the maximum asymmetrical through-fault on the secondary side. The setting must be above the transformer inrush current to prevent nuisance tripping.

3.1.2.3.4 Differential Protection, Device 87T

Differential protection, device 87T, is typically used on transformers 10 MVA and above. The current actuating the differential relay is the net difference between input and output currents of the transformer properly transformed to the relay via current transformers. The current transformers may be located on the transformers' primary and secondary bushings (e.g., bushing CTs) or they may be located remotely on circuit breakers to give a larger "zone of protection". The most common type of differential relay is the percentage differential relay with harmonic restraint. This relay incorporates both percentage differential restraint and harmonic restraint.

The percentage differential restraint ensures accurate discrimination between internal and external faults at high fault currents. This prevents undesired tripping of the relay due to mismatch of relay currents, and/or relay taps for transformer through-faults. Relay currents may be mismatched due to CT ratio imbalances, CT saturation, CT wire length and transformer turns ratio due to tap changer operation. The amount of restraint is stated as percentage of the differential or net current to the relay. The relays are usually provided with several percent slope taps (15-40%). Variable percentage slope can also be provided which provides high sensitivity at low current magnitudes with an increase in percentage ratio at higher currents.

The harmonic restraint feature enables the relay to distinguish between transformer magnetizing inrush and an internal fault by the difference in waveform. As a minimum, second harmonic currents that are always present during transformer magnetizing are used to restrain the relay during energization of the transformer.

The CTs used for differential protection of wye-delta transformers must be connected in delta on the transformer wye winding, and wye on the delta winding. This is done to compensate for the 30° phase angle shift introduced by the wye-delta bank, and to eliminate zero sequence currents caused by external faults on the wye side of the transformer from operating the relay.

Phase-to-ground faults on either the wye- or delta-connected windings for solidly grounded systems will cause two of the three phases of the differential relays to operate. If either side of the transformer is connected to a low resistance grounded system, then the differential relay operation will be marginal for ground faults on the low resistance side, and alternative ground fault protection should be used. If either side of the transformer is high resistance or ungrounded, then the differential relay will not operate for ground faults on that side of the transformer.

3.1.2.3.5 Ground Fault Protection

Transformer ground fault protection can be provided by either differential relays or by overcurrent relays on solidly grounded systems. Dedicated ground fault protection schemes should be provided for transformers on resistance and ungrounded systems.

The following ground fault protection schemes can be used on either solidly grounded systems or on low resistance grounded transformers. Scheme selection depends upon the required sensitivity, coordination and physical restraints.

3.1.2.3.5.1 AC Time Ground Overcurrent Relays, Devices 51N & 51NY

An AC time ground overcurrent relay functions when the ground fault current exceeds a predetermined value for a given time. The current and operating time are inversely proportional. They should be used when time coordination with other system ground fault protection is required. If time coordination is not required, then an instantaneous ground overcurrent relay can be used. Ground fault relays can be set more sensitive than phase fault relays since they do not see phase currents. The time ground overcurrent relays can be located either in the transformer neutral or residually connected in the CT secondary (CT neutral) for the phase overcurrent relays.

Device 51N is located in the transformer wye winding neutral. Device 51N can be set more sensitively than residually connected ground fault relays since they do not see load current unbalance and CT dissymmetry unbalance. This device provides ground fault protection for wye windings and ground faults occurring downstream of secondary wye windings (through faults) for the following systems:

1. Three-phase, three-wire systems with the transformer neutral grounded.

2. Three-phase, four-wire, single-point grounded systems with the ground fault relay CT located between the neutral conductor and the system ground. (Note: Device 51N would have to be set greater than the load current unbalance if the CTs were located between the neutral conductor and the transformer neutral.)

Device 51N may not be effective if the electrical system neutral is grounded at more than one point for the following reasons:

1. The unbalanced load current may divide between the system neutral conductor and the ground conductor, which will require device 51N to be set less sensitively.

2. Not all of the downstream ground fault current will return to the transformer neutral, which will require a more sensitive setting.

Device 51NY is residually connected in the neutral of the phase CTs on the wye winding side of the transformer. Device 51NY must be set greater than the maximum load current unbalance and CT dissymmetry unbalance. It provides ground fault protection for primary wye windings, back fed secondary wye windings and ground faults occurring downstream of secondary wye windings (through faults).

3.1.2.3.5.2 Instantaneous Ground Overcurrent Relays, Devices 50N & 50NY

An instantaneous ground overcurrent relay functions instantaneously when the ground fault current exceeds a predetermined value. If time coordination for ground faults is not required, then an instantaneous ground overcurrent relay can be used alone. If a high current pickup for severe ground faults is wanted, then an instantaneous ground overcurrent relay can be used in conjunction with AC time ground overcurrent relays (51N, 51NY). The relay is located either in the transformer neutral or residually connected in the CT secondary.

Device 50N is located in the transformer wye winding neutral. When used with device 51N, it is normally set to pick up only for severe ground faults. The pickup setting must be greater than downstream protective devices to prevent nuisance tripping. When used alone and coordination is not required, its pickup is set very sensitive. Other sensitivities and limitations for both high and low set device 50Ns are basically the same as stated for device 51N (AC time ground overcurrent relay).

Device 50NY is residually connected in the neutral of the phase CTs on the wye winding side of the transformer. When used with device 51NY it is normally set to pickup only for severe ground faults. The pickup setting must be greater than downstream protective devices to prevent nuisance tripping. When used alone and coordination is not required, its pickup is set very sensitively. Other sensitivities and limitations for both high and low set device 50NYs are basically the same as stated for device 51NY.

3.1.2.3.5.3 Zero Sequence Overcurrent Relays, Device 50G

Zero sequence instantaneous ground overcurrent relays can also be used. This method uses a toroidal or window CT. Either the transformer neutral conductor and/or the main conductors pass through the window CT. The instantaneous relay must be matched to the window CT to obtain the required sensitivity for a given application. This scheme is only applicable to low voltage and medium voltage systems where all of the conductors can be fitted through the window CT. For three-phase, four-wire systems, the three-phase conductors and the neutral conductor are passed through the window CT. Load unbalance will therefore not produce any output current in the window CT secondary, and device 50G can be made very sensitive. Other sensitivities and limitations for device 50G are basically the same as stated for the AC time ground overcurrent relays.

3.1.2.3.5.4 Dedicated Ground Fault Protection for Transformer Grounded Wye Winding, Devices 67N & 87TN

Both directional ground relays (67N) and ground differential relays (87TN) can detect ground faults in the transformer wye-connected windings. Both protection schemes can discriminate between transformer internal faults and faults external to the transformer protected zone. Both schemes will operate for an internal ground fault in the wye winding, irrespective of the wye winding adjacent breaker position. (Source must be available from delta side when wye side breaker is open.) These schemes will operate properly for internal transformer ground faults when an external zero sequence current source exists (external system ground) but will not operate for external ground faults.

3.1.2.3.5.5 Dedicated Ground Fault Protection for Transformer Delta Winding, Devices 50GD & 51ND

The transformer delta winding and the phase conductors between the CTs and the delta winding can be protected by a time ground overcurrent relay, Device 51ND, when the system is either solidly or low resistance grounded (an external source of zero sequence current is available). The relay is residually connected in the CT secondary. If the CTs are located on adjacent breakers, then the transformer delta winding, cable, bus and associated bushings are all provided with sensitive ground fault protection.

Zero sequence instantaneous ground overcurrent relays, Device 50GD, can also be used in similar applications. All three of the transformer phase conductors are passed through the window CT. This scheme is basically the same as described for protection on the transformer wye winding and has the same physical limitations.

3.1.2.3.5.6 Transformer Ground Fault Protection for High Resistance Grounded System, Device 59N

Time overvoltage relays, Device 59N, connected across the neutral resistance either directly or on the secondary of a neutral voltage transformer should be used.

3.1.2.3.5.7 Fire Detection Systems for Ground Faults in Network Vaults

The heat and smoke generated by an arcing ground fault can be sensed by a fire detection system. This is an acceptable alternative to secondary-side electrical protection. A heat detector should be located within the network protector for each transformer, and a smoke or heat detection system should be located in the transformer room in accordance with the recommendations contained in 5-48, *Automatic Fire Detection*. Actuation of one heat detector or two smoke detectors should be arranged to trip the appropriate primary and secondary breakers.

3.1.2.3.6 Network Protectors

The network protector is normally flange mounted directly on the network transformer low voltage terminals. The network protector contains the following components: low voltage air circuit breaker (ACB), controls for the ACB, and network relays. Network protectors trip for faults occurring on the primary side of the network transformer and/or when a power reversal occurs with power flowing from the secondary side of the network transformer to the primary side.

The watt-var network master relay has superior operating characteristics over the standard watt network master relay. If a primary-side line-to-ground fault occurs and a single primary fuse operates without tripping the feeder breaker, the unfaulted phases may still supply power to the network. Under these conditions the net three-phase power flow in the network protector is not in the reverse direction and the standard watt master relay will not operate. The reactive flow (vars) in the network protector will be in the reverse direction. The watt-var master relay properly connected to see this reverse reactive flow will operate for this condition.

3.2 Loss History

Nearly 50% of the dollar loss for transformers reported to FM Global occurs in the utility industry. Another 10% occurs for transformers in the chemical industry, 7% in pulp and paper and 6% at commercial locations.

A study of modern transformer breakdown records shows that between 40% and 60% of the transformer failures are traced to windings. Statistics of FM Global Loss and Operational Analysis Department statistics show that 60% of transformer failures involve the windings. IEEE statistics from IEEE Std. 493-1990, *Design of Reliable Industrial and Commercial Power Systems*, report that 53% of the failures involve windings. Doble Engineering surveys reports that for the last five years, 44% of the failures involve windings (Table 4).

According to the Doble Engineering's transformer winding location failure analysis survey, 36% of the failures occur in the high voltage winding and 41% occur in the low voltage winding (Table 5). Turn-to-turn faults represent 30% of the winding failures, phase-to-ground is 16%, and phase winding-to-winding is 14% (Table 6). The cause of the failures is not always clearly identified because all evidence is often eliminated by the very nature of the breakdown.

Table 4. Transformer Failure Analysis 1989–1993[1]

Components	Total No.	Total %
Bushings	84	6
Coil Blocking	102	7
Core & Clamping Assembly	84	6
De-Energized Tap Changer Assembly	43	3
Insulating Liquid	82	6
Lead & Lead Support Structure	70	5
Load Tap Changer Assembly	237	17
Tank, Gasket, Cooling Equip. & Access.	55	4
Winding	658	47
Not Identified	87	6
Total	1389	

[1]Transformer Failure Analysis statistics from Doble Engineering Company, Watertown, MA

Table 5. Transformer Winding Location Failure Analysis 1989–1993[1]

Location of Winding Failure	Total No.	Total %
Common (LV on Autotransformer)	20	3
Series (HV on Autotransformer)	20	3
High Voltage	273	36
Low Voltage	314	41
Regulating or Tap	56	7
Tertiary	39	5
Not Indicated	47	6

[1]Transformer Failure Analysis statistics from Doble Engineering Company, Watertown, MA

Table 6. Transformer Winding Insulation Failure Analysis 1989–1993[1]

Winding Insulation	Total No.	Total %
Winding to Ground	189	16
Winding to Winding	129	14
Phase to Phase	42	5
Turn-to-Turn	263	29
Winding Distortion or Movement	103	11
Not Identified	189	16

[1]Transformer Failure Analysis statistics from Doble Engineering Company, Watertown, MA

4.0 REFERENCES

4.1 FM Global

Data Sheet 4-1N, *Fixed Water Spray Systems for Fire Protection.*

Data Sheet 5-10, *Protective Grounding for Electric Power Systems and Equipment.*

Data Sheet 5-11, *Lightning and Surge Protection for Electrical Systems.*

Data Sheet 5-19, *Switchgear and Circuit Breakers.*

Data Sheet 5-20, *Electrical Testing*.

Data Sheet 5-48, *Automatic Fire Detection*.

4.2 Other

NFPA 70, *National Electric Code (NEC)*, 1996

NFPA 850, *Electric Generating Plants*, 1996

ANSI/IEEE Std 979-1984

Code of Federal Regulations: Part 761-Polychlorinated Biphenlys (PCBs)

ANSI/IEEE C37.100-1981

ANSI/IEEE C57.109-1985

ANSI/IEEE Std.493-1990, *Design of Reliable Industrial and Commercial Power Systems*.

ANSI/IEEE Std. C57.91

ANSI/IEEE Std. C57.92

ASTM D448, *Standard Classification for Sizes of Aggregate for Road and Bridge Construction*.

European Standard EN 50195, *Code of Practice for the Safe Use of Fully Enclosed Askarel-Filled Electrical Equipment*.

APPENDIX A GLOSSARY OF TERMS

FM Approved: references to "FM Approved" in this data sheet means the product or service has satisfied the criteria for Approval by FM Approvals. Refer to the *Approval Guide* for a complete listing of products and services that are FM FM Approved.

Higher secondary voltages: secondary voltages equal to or greater than 480 volts, including 480/277 volt systems.

Lower secondary voltage: transformers with secondary voltages below 480 volts.

Navigable waterway: Navigable waterway is defined by 40 CFR Part 112 as:

a) All waters that are currently used, were used in the past, or may be susceptible to use in interstate or foreign commerce, including all waters subject to the ebb and flow of the tide.

b) All interstate waters, including interstate wetlands, mudflats, and sandflats.

c) All other waters such as intrastate lakes, rivers, streams (including intermittent streams), wetlands, mudflats, sandflats, sloughs, prairie potholes, wet meadows, playa lakes, or natural ponds, the use, degradation, or destruction of which could affect interstate or foreign commerce including any waters that could be used for recreational purposes, or from which fish or shellfish could be taken and sold in interstate or foreign commerce; or that are used or could be used for industrial purposes by industries in interstate commerce.

Network transformer: these transformers are located in vaults in buildings or adjacent to buildings. The vaults contain two or more power transformers. These transformers are supplied from different transmission or distribution lines and are paralleled on their low voltage side through circuit interrupting devices called "network protectors". Typically high voltage current interrupting devices have not been used in the network vault. The low-voltage bus of a network vault may be electrically tied to a number of other vaults to form a network secondary distribution system, called a low-voltage network grid.

Primary winding: the winding into which energy normally flows. The primary winding can be energized from the secondary winding under abnormal conditions.

Radial transformer: a transformer that can only be energized from the primary winding.

Secondary winding: the winding from which energy flows during normal operation.

In or near commercial buildings: within the interior of, on the roof of, attached to tha exterior wall of, in the parking area serving, or within 30 meters of a non-industrial non-substation building. Commercial buildings are typically accessible to both members of the general public and employees, and include: 1) Public assembly properties, 2) educational properties, 3) institutional properties, 4) residential properties, 5) stores, 6) office buildings, and 7) transportation centers (e.g., airport terminal buildings, subway stations, bus stations, or train stations).

APPENDIX B DOCUMENT REVISION HISTORY

January 2005. The following changes were done for this revision:

1. Section 2.2 Indoor Transformers, recommendations 2.2.1.2.2 & 2.2.1.3.2.2. A protection alternate to CO-2 of an FM Approved gaseous agent protection system or a water mist system FM Approved for machinery spaces is recommended. Also, where automatic sprinkler protection is used, the density has been increased to 0.3 gpm/ft^2 (15 mm/min) from 0.2 gpm/ft^2 (10 mm/min).

2. Section 2.3 Outdoor Transformer, recommendation 2.3.1.2.3 for open pit containment system. Where automatic sprinkler protection is used, the sprinkler density has been increased to 0.3 gpm/ft^2 (15 mm/min) from 0.15 gpm/ft^2 (6 mm/min). Where a flame arrestor is used to increase the amount of time before burning oil enters the pit Size No 5 rather than Size No 2 ASTM D448 Standard Classification for Sizes of Aggregate for Road and Bridge Construction should be used. Size No 5 is closer to the 1.5 in (3.8 cm) washed and uniformly sized rock tested at the FM Global Research Campus.

3. Section 3.1.1, Approved and Equivalent Transformer. A transformer equivalent to an FM Approved transformer is defined as a transformer with a UL listing per NEC Section 450-23 with electrical protection to clear sustained low current faults. The reference to NEC 450-23 was left out of the previous edition. Transformers complying with NEC 450-23 include four of the five safeguards requested for an FM Approved transformer. Low current fault protection is the remaining safeguard.

May 2003. The following changes were done for this revision:

1. Tables 2a and 2b Separation Distances. The change allows medium sized transformers containing FM Approved less flammable fluids to be located as close to buildings and to other transformers as small transformers were in the previous standard. This provided there is adequate space for inspection and maintenance. Medium sized transformers may contain up to 10,000 gal (37.9 m^3) of fluid.

2. Section 2.3.1.2 Containment. The change increases the quantity of FM Approved less flammable fluid in a transformer before a containment system is recommended. It increases the size of the transformer to 1320 gal (5 m^3) for transformers containing all FM Approved less flammable fluids. It further increases the size to 2640 gal (10 m^3) if the fluid is certified as biodegradable and if a release does not expose navigable waterways. A definition is included for navigable waterways. The fluid would have to be certified as biodegradable by the responsible governmental authority.

3. Minor editorial changes were made to Section 2.3.1.2.1.4.

January 2001. The recommendation for the smoke detection for electrical rooms was revised to provide consistency within 5-series data sheets.

September 2000. This revision of the document was reorganized to provide a consistent format.

The following major changes have been made:

a) Addition of emergency power supply recommendation for mechanical ventilation (Section 2.2.1.1.3).

b) Change requirement for smoke detection to fire detection (Section 2.2.1.1.4).

c) Add recommendation for location of rooms containing network transformers to outside wall where possible (Section 2.2.1.2).

d) Addition of fire protection recommendations for multiple indoor oil insulated transformers (Section 2.2.1.3.2).

e) Open pits without protection acceptable containment for FM Approved less flammable fluid insulated transformer (Section 2.3.1.2.1.2 and 2.3.1.3.1).

December 1998. Editorial changes were made.

APPENDIX C SUPPLEMENTARY INFORMATION

C.1 Other Standards

There are three standards that cover transformers as follows:

C.1.1 NFPA 70, National Electric Code

Fire protection for transformers is covered under Article 450 of the *National Electric Code (NEC)*. This includes dry-type, less-flammable liquid-insulated, and oil-insulated transformers installed both indoors and outdoors.

The major difference between this data sheet and the NEC is the treatment of PCB-filled or PCB-contaminated transformers. This data sheet recommends that these transformers be replaced if the loss exposure warrants. NEC and OSHA regulations allow the use of existing PCB-filled or PCB-contaminated transformers provided they have been equipped with enhanced electrical protection.

C.1.1.1 Indoor Transformers

Dry-Type transformers

(450-21b) Over 112.5 kVA. Install in room of fire resistive construction.

Exception 1. Transformers with 175°F (80°C) rise and higher separated from combustible material by a fire resistant heat-insulating barrier or by a minimum distance of 6 ft (1.8 m) horizontally and 12 ft (3 m) vertically.

Exception 2. Transformers with a 175°F (80°C) rise or higher rating and completely enclosed except for ventilation openings.

Over 35,000 volts. Install in vault (3 hour fire resistance rating for walls and roof).

(450-23) Less Flammable Liquid Insulated Transformers

Up to 35,000 volts. Can install in Type I and II buildings provided: a) no combustible storage; b) a liquid containment area is provided; and c) fire point of the liquid exceeds 570°F (300°C).

Over 35,000 volts. Install within a vault.

Use of these transformers is allowed when they are attached to, adjacent to, or on the roof of Type I or II buildings. They may be used in other types of buildings provided fire barriers, space separation and requirements for the listing of the liquid are followed.

Type I building structural components are noncombustible or limited combustible and, except for exterior nonload bearing walls, they have a fire resistance rating. Type II building structural components are noncombustible or of limited combustible construction and may not have a fire resistance rating.

(450-24) Nonflammable Liquid Insulated Transformers

Up to 35,000 volts. Shall be provided with a liquid confinement area and a pressure relief vent.

Over 35,000 volts. Shall be installed in a vault.

(450-25) Askarel Insulated Transformers

Over 35,000 volts. Shall be installed in a vault. Also see OSHA regulations.

Oil Insulated Transformers

(450-26) Indoors. Shall be installed in a vault. The following exceptions apply:

1. If total capacity does not exceed 112.5 kVA, the vault can be constructed of 4-in. (102 mm) thick reinforced concrete.

2. If voltage does not exceed 600 and total transformer capacity does not exceed 10 kVA, the transformer may be installed in a combustible building; or if transformer capacity does exceed 75 kVA, the transformer may be installed in a building of fire resistant construction.

3. Oil-insulated transformers can be used in a detached building if the building does not present a fire exposure to other buildings or property and if it is used only for electric service and is accessible only to qualified persons.

C.1.1.2 Outdoor Transformers

Combustible material, combustible buildings, door and window openings shall be safeguarded from fires in oil-insulated transformers. Methods of achieving this are space separation, fire resistant barriers, automatic water spray and enclosures to confine oil from a ruptured transformer.

C.1.2 NFPA 850

NFPA 850, *Fire Protection for Fossil Fueled Steam Electric Generating Plants*, contains recommended practices for both indoor and outdoor transformers.

There is no conflict with NFPA 850.

This data sheet gives separate distances between transformer and buildings based on the quantity of fluid in the transformer and the type of construction of the building. NFPA 850 assumes that the building construction will be noncombustible (typically insulated metal on steel frame) and gives spacing based on the volume of fluid in the transformer. The separation distances given in this data sheet are the same as those given in NFPA 850 for this type of construction.

This data sheet allows separation, barriers or water spray protection to be used to protect transformers. NFPA 850 recommends that oil-filled main, station service and startup transformers be protected by water spray or foam water systems.

C.1.2.1 Indoor Transformers

Where oil-filled transformers of greater than 100 gal (380 dm^3) oil capacity are installed, they should be separated from adjacent areas by fire barriers of 3 hr fire resistance rating. Where an automatic fire suppression system is provided, the fire barrier rating may be reduced to one hour.

C.1.2.2 Outdoor Transformers

Where transformers are in excess of 500 gal (1.9 m^3) oil capacity, a 2-hr-rated fire barrier or space separation is needed to protect adjacent structures including other transformers. The space separation is dependent on the quantity of oil in the transformer. Twenty-five feet (7.6 m) is needed for 500 to 5,000 gal (1.9 to 19 m^3); 50 ft (15.2 m) is needed where quantities are in excess of 5,000 gal (19 m^3). Where a fire wall is not provided, the edge of the oil spill (dike) must be a minimum of 5 ft (1.5 m) from the exposed structure.

In addition, oil-filled main, station service, and startup transformers should be protected by water spray or foam-water systems.

C.1.3 IEEE Std 979-1984

Fire protection guidance for indoor and outdoor substations is covered in the ANSI/IEEE Std 979-1984.

There is a difference with regard to separation distances. This data sheet recommends a 25 ft (7.6 m) separation between mineral oil insulated transformers containing from 500 to 5,000 gal (1.9 to 19 m^3) and 50 ft (15.2 m) separation between transformers continuing in excess of 5,000 gal (19 m^3) of mineral oil. Water spray or a 2-hour rated fire barrier are given as alternatives.

IEEE 979 recommends 30 ft separation between transformers with more than a 333-kVA rating (approximately 100-150 gal [0.38-0.57 m^3]). An automatic extinguishing system or a 1-hour fire barrier are given as alternatives.

C.1.3.1 Indoor Transformers

The use of oil-filled equipment inside a building is discouraged. If oil-filled transformers are used, a transformer room or vault with a fire rating sufficient to withstand the largest credible fire is recommended. Installation of fixed fire extinguishing systems and containment is also recommended.

C.1.3.2 Outdoor Transformers

Spacing of transformers from buildings depends on the quantity of oil contained within the transformer. Transformers containing 2000 gal (7.6 m^3) or more of oil should be a minimum of 20 ft (6.1 m) from an exposed building regardless of protection provided. It is recommended that a minimum separation distance of 50 ft (15.2 m) from buildings be used unless the building has walls equivalent to or are protected by a 2-hour fire barrier. The separation distance for transformers containing smaller amounts of oil ranges from 10 ft (3 m) for 75 kVA or less, to 20 ft (6.1 m) for transformers from 76 to 333 kVA, and 30 ft (9.1 m) for more than 333 kVA. Oil containment systems are also recommended in the form of yardstone, diked areas and pits.

A separation distance between large transformers of 30 ft (9.1 m) of clear space or a one hour fire barrier is recommended.

Also automatic extinguishing systems should be considered for all liquid-cooled transformers except those that are adequately separated or that contain less than 500 gal (1.9 m^3) of combustible transformer liquid.

C.1.4 Code of Federal Regulations: Part 761—Polychlorinated Biphenyls (PCBs)

The following regulations and list of definitions are excerpts from the *Code of Federal Regulations*: Part 761 *—Polychlorinated Biphenyls (PCBs) Manufacturing, Processing, Distribution in Commerce, and Use Prohibition*. Subpart B—*Manufacturing, Processing, Distribution In Commerce, and Use of PCBs and PCB Items*. § 761.30 *Authorizations*.

"Use in and servicing of transformers (other than railroad transformers). PCBs at any concentration may be used in transformers and may be used for purposes of servicing including rebuilding these transformers for the remainder of their useful lives, subject to the following conditions:

1. Use conditions.

a) The use and storage for re-use of PCB transformers that pose an exposure risk to food or feed is prohibited.

b) The use of network PCB transformers in or near commercial buildings is prohibited except for:

i) All network PCB transformers with secondary voltages below 480 volts in or near commercial buildings not located in sidewalk vaults that have not been removed from service must be equipped with electrical protection to avoid transformer ruptures caused by high current faults, or must be removed from service.

ii) Current-limiting fuses or other equivalent technology must be used to detect sustained high current faults and provide for the complete de-enerigzation of the transformer within tenths of a second before transformer rupture occurs. The installation, setting, and maintenance of current-limiting fuses or other equivalent technology to avoid PCB transformer ruptures from sustained high current faults must be completed in accordance with good engineering practices.

c) The installation of PCB transformers, which have been placed into storage for re-use or which have been removed from another location, in or near commercial buildings is prohibited.

d) All radial PCB transformers with secondary voltages below 480 volts in use in or near commercial buildings must be equipped with electrical protection to avoid transformer ruptures caused by high current faults.

i) Current-limiting fuses or other equivalent technology must be used to detect sustained high current faults and provide for the complete de-energization of the transformer or complete de-energization of the faulted phase of the transformer within several hundredths of a second. The installation, setting, and maintenance of current-limiting fuses or other equivalent technology to avoid PCB transformer ruptures from sustained high current faults must be completed in accordance with good engineering practices.

e) All radial PCB transformers with secondary voltages equal to or greater than 480 volts, including 480/277 volt systems in use in or near commercial buildings that have not been removed from service must be equipped with electrical protection to avoid transformer ruptures caused by:

i) High current faults.

Current-limiting fuses or other equivalent technology must be used to detect sustained high current faults and provide for the complete de-enerigzation of the transformer within several hundredths of a second before tank rupture occurs. The installation, setting, and maintenance of current-limiting fuses or other equivalent technology to avoid PCB transformer ruptures from sustained high current faults must be completed in accordance with good engineering practices.

ii) Sustained low current faults. Be equipped with protection to avoid transformer ruptures caused by sustained low current faults.

iii) Pressure and temperature sensors (or other equivalent technology which has been demonstrated to be effective in early detection of sustained low current faults) must be used.

iv) Disconnect equipment must be provided to insure complete de-energization of the transformer in the event of a sensed abnormal condition caused by a sustained low current fault. The disconnect equipment must be configured to operate automatically within 30 seconds to one minute of the receipt of a signal indicating an abnormal condition. The disconnect equipment can also be configured to allow for manual de-energization from a manned on-site control center within one minute of the receipt of a signal indicating an abnormal condition. If automatic operation is selected and a circuit breaker is utilized for disconnection, it must also have the capability to be manually opened if necessary.

v) The enhanced electrical protective system required for the detection of sustained low current faults and the de-energization of transformers must be properly installed, maintained, and set sensitive enough to detect sustained low current faults and allow for rapid de-energization prior to PCB transformer rupture (either violent or non-violent rupture) and release of PCBs."

C.2 Trade Names for Askarels

Trade Names for Insulating Liquids having PCBs as a major constituent.

The following is a list of some typical trade names for insulating liquids having PCBs as a major constituent.

This list is included in the Annex A of the European Standard EN 50195 "Code of practice for the safe use of fully enclosed askarel-filled electrical equipment". This European Standard was prepared by the Technical Committee CENELEC TC 14, Power transformers, and was approved by CENELEC as EN 50195 on 1996-07-02.

The generic term "askarels" is used in this Standard for transformers and capacitors insulating/cooling liquids having PCBs as a major constituent.

CENELEC is the European Committee for electrotechnical Standardization. CENELEC members are bound to comply with the CEN/CENELEC Internal Regulations which stipulate the conditions for giving the European Standards the status of a national standard without any alteration. National and Local Authority (if any) take priority.

CENELEC members are the national electrotechnical committees of Austria, Belgium, Denmark, Finland, France, Greece, Iceland, Ireland, Italy, Luxembourg, Netherlands, Norway, Portugal, Spain, Sweden, Switzerland and United Kingdom.

Table 7. Some Typical Trade Names for Askarels

Trade Name	*Manufacturer*	*Country of Origin*
Asbestol	American Corporation	USA
Aceclor	ACEC	Belgium
Apirolio	Caffaro	Italy
Aroclor	Monsanto	USA
Bakola 131	Monsanto	USA
Clorinol	Sprague Electric	USA
Clophen	Bayer	Germany
Diaclor	Sangamo Electric	USA
Dykanol	Cornell Dubilie	USA
Elemex	McGraw Edison	USA
Eucarel	Electrical Utilities	USA
Hyvol	Aerovox	USA
Inerteen	Westinghouse	USA
KaneChlor	Kanegafuchi	Japan
No-flamol	Wagner Electric	USA
Pyralene	Prodelec	France
Pyranol	General Electric	USA
Pyroclor	Monsanto	Great Britain
Saf-T-Kuhl	Kuhlmann Electric	USA
Sovlol/Sovol/Solvol	Sovlol/Sovol	Soviet Union
Ugilect		

APPENDIX D BIBLIOGRAPHY

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9. Johnson, D. L., *Conserving Inherent Transformer Life Expectancy*, Bonneville Power Administration, 51st Annual International Conference of Doble Clients.

FM Engr. Comm. Aug 1996

CATALYTIC STEAM - HYDROCARBON REFORMERS

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1.0 SCOPE

This data sheet deals with the production of hydrogen by the catalytic steam-reforming method. The method described uses natural gas (methane) as feed stock. This is the method used in most ammonia synthesis plants which are, by far, the largest consumers of the hydrogen element. Similar equipment, especially for the primary reforming stage as described herein, is also used to produce hydrogen in other industries including the food industry for hydrogenation, synthesis of various other hydrogen containing compounds, and the production of pure hydrogen for bulk sales.

A description of reforming equipment is given along with operating problems and loss experience.

Recommendations are set forth for operation, inspection, and maintenance of the equipment.

1.1 Changes

January 2000. This revision of the document has been reorganized to provide a consistent format.

2.0 LOSS PREVENTION RECOMMENDATIONS

2.1 Equipment and Processes

2.1.1 Provide reformer furnaces with combustion controls and safeguards in conformity with Data Sheet 6-10, *Process Furnaces*.

2.1.2 Provide low water alarm for cooling water jackets of transfer header and secondary reformer, and provide means for testing same.

2.1.3 Provide sufficient inspection ports in furnace walls to permit observation of all reformer tubes.

2.1.4 Consider installation of creep monitoring devices on outlet headers of primary reformer (See Fig. 1).

2.1.5 Specify and procure tubing of superior quality for reformer tube service.

2.1.6 Provide a reliable source of emergency cooling water for mechanical and pressure equipment in the event of failure of normal supply due to loss of electric power or other occurrence.

2.1.7 Provide for sufficient emergency boiler feedwater supply in order to generate steam required to cool the reformer and to reduce its temperature in such a manner to avoid cracking of the tubes and headers.

2.2 Operation and Maintenance

2.2.1 Operation

2.2.1.1 When loading, determine and record the weight of catalyst loaded to each tube.

2.2.1.2 Maintain steady state conditions in the reformer as far as possible to avoid thermal cycling of tubing.

2.2.1.3 Make regular visual observations of reformer furnace through peepholes during each shift and log such observations noting any changing conditions, e.g., development of tube bulges or fissures, or deterioration of refractory materials.

2.2.1.4 Conduct routine scans of tube temperatures each shift using reliable pyrometric equipment.

2.2.1.5 Conduct weekly infrared thermal imaging scans of the secondary reformer to detect possible "hot spots" in the pressure boundary shell that may be indicative of deteriorating refractory lining.

2.2.1.6 Keep reformers hot during shutdowns of less than seven days unless work must be done in the reformer.

2.2.1.7 Do not operate primary reformer without steam.

2.2.1.8 Maintain catalyst in optimum condition by complete desulfurization of feedstock, use of demineralized water for generating process steam, and avoidance of condensate formation in the reformer during shutdowns. It should be noted that the effect of a relatively small sulfur concentration in the feedstock is to dramatically increase tube wall temperature.

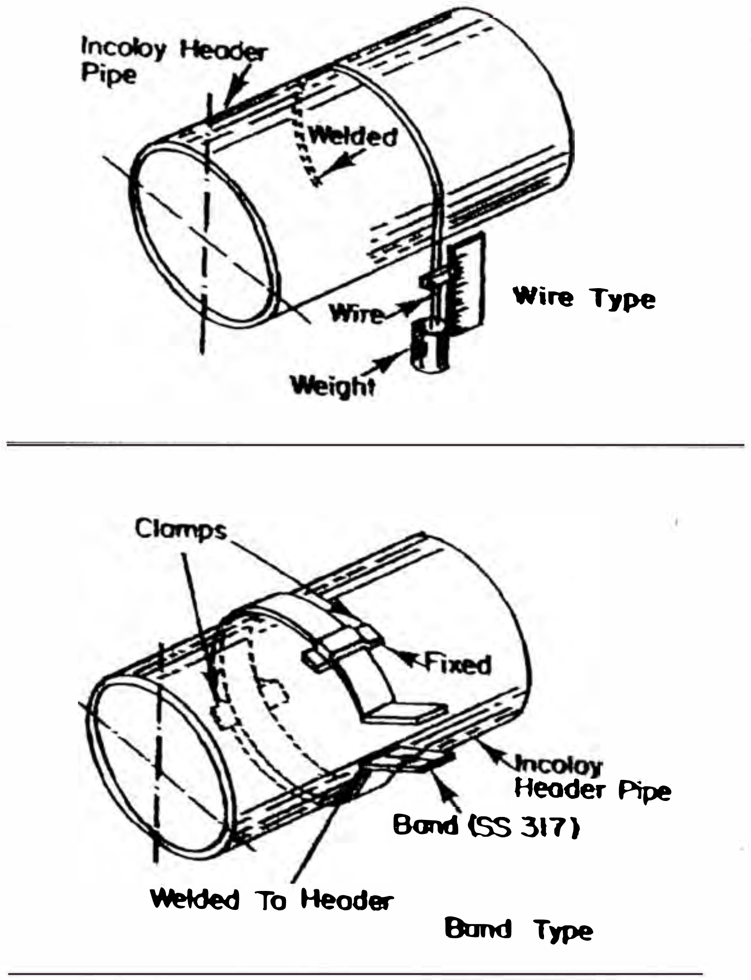

Fig. 1. Creep monitoring devices.

2.2.1.9 To provide protection during shutdown in extremely code weather:

a) Purge steam and water from reformer tubes with inert gas such as nitrogen or CO_2.

b) Drain all water jackets.

c) Provide double block and bleed drains at any point where steam or water could be admitted to the unit.

d) Keep reformer tubes warm by means of a few burners or lazy flame.

2.2.1.10 Maintain optimum adjustment of firing to provide uniformity from row to row of tubing and the best feasible heat flux profile from top to bottom of the tubes.

2.2.1.11 Avoid sudden pressurizing and depressurizing of reformer tubes.

2.2.1.12 Observe precautions to prevent overheating of activated carbon used to desulfurize natural gas. Ignition temperature can be as low as 430°F (220°C).

2.2.1.13 Emergency shutdown procedures should be written, posted, and explained to operating personnel. Periodic emergency shutdown procedures should be put into practice by holding simulated emergency drills.

2.2.2 Maintenance

2.2.2.1 To prevent development of "hot spots," vibrate tubes during turnarounds to eliminate voids or channels formed by catalyst shrinkage.

2.2.2.2 When catalyst activity loss becomes noticeable, change catalyst with minimum delay.

2.2.2.3 Make internal inspection of secondary reformer at each catalyst change. Examine refractory closely for cracks or other deterioration. Make necessary repairs or replacements if deterioration is severe.

2.2.2.4 Conduct comprehensive inspection of all reformer tubes on at least an annual basis. Inspection should include complete scanning of all tubes for creep and magnetic permeability (if applicable) with continuous recording of readings for future reference in establishing life expectancy.

2.2.2.5 Scanning for mid-wall discontinuities by either the high frequency eddy current or ultrasonic "through-transmission" technique is also recommended annually.

2.2.2.6 Schedule maintenance and inspections to minimize the need for shutdowns during cold weather.

2.2.2.7 Maintain support systems and other devices provided to accommodate thermal expansion of tubes, headers, risers, and collection manifolds in good calibration and condition.

2.2.2.8 Keep temperature measuring instruments in a good state of repair and calibration. Give all operators the same instructions to minimize differences in readings from operator interpretation.

2.2.2.9 Follow catalyst suppliers' detailed instructions for loading, start-up, operation, shutdown, and removal of catalyst.

2.2.2.10 In addition to normal visual and pyrometer checks by shift operators, conduct weekly optical pyrometer surveys of pigtails, tube supports, headers, manifolds, transfer lines, and secondary reformer shells.

2.2.2.11 Check for free movement of all parts, e.g., tube supports and furnace penetration seals, to ascertain there is no restraint to expansion and contraction of tubes.

3.0 SUPPORT FOR RECOMMENDATIONS

3.1 Loss History

During a recent ten year period, 57 reformer losses were reported at FM Global insured properties. Forty-seven of these occurred in ammonia synthesis plants. The balance involved reformers producing hydrogen for the following processes:

	No. of Losses
Hydrogenation in the food industry	4
Methanol production	3
Polyols production	1
Furfural alcohol production	1
Bulk sales of hydrogen	10

The 57 reported losses resulted from failure of the following parts:

Primary Reformers	*No. of Losses*
Catalyst tubes (single and multiple)	13
Collection headers	13
Steam preheater tubes	7
Outlet pigtails	6
Transfer lines	5
Riser tube	1
Air preheater tube	1
Gas feeder line	1
Catalyst	1
Furnace refractory	1
	49

Secondary Reformers	
Shells	6
Head	1
Outlet transition tube	1
	8

3.2 Inspection of Reformer Tubes

Although there is no single "best" method available for inspection of reformer tubes, several methods are useful in the detection of "bad tubes" that should be replaced. None of these methods, however, provide a guarantee that any given tube will not fail before the next turnaround.

Tube inspection, as defined here, is intended to identify tubing which should be retired in advance of onstream failure. A single tube failure and resultant unplanned shutdown can cause a loss in production of hundreds of thousands of dollars. This potential economic loss, coupled with the possibility of additional mechanical damage to the unit as a result of the upset, justifies the expense of a comprehensive and regular furnace tube inspection program. Brief descriptions of available inspection methods follow. Further details on various types of non-destructive examination are given in Data Sheet 17-1, *Nondestructive Examination*.

3.2.1 Measurement of Metal Creep

Measurement of localized suspicious areas can be readily spot checked by girdling the tube with a very flexible tape or strip of paper about ½ in. (12.7 mm) wide and long enough to go around the tube with several inches to spare. Mark the original circumference on the tape as a reference. By slipping the tape around the tube, swelling may be readily detected.

A comprehensive examination can be done with minimum downtime using an electronic tube caliper which fits around the tube and can scan full tube length. It is propelled by a winch and cable attached to an aluminum mast. Reformer tubes can be scanned at the rate of about ten per hour. No scaffolding is required and the catalyst can remain in place. Tube dimensions are indicated on a recorder output which also provides a permanent record of the tube scan. Accuracy is reported to be ± 0.005 in. (0.127 mm).

3.2.2 Measurement of Magnetic Permeability

Localized suspicious areas can be spot checked for magnetic attraction by means of a small permanent magnet. Any area having an attraction, however slight, is an indication that deterioration is in progress and the location should also be checked for creep.

Equipment is available to conduct comprehensive scans of reformer tubes for magnetic permeability employing a low frequency eddy current method. The equipment is designed to rapidly scan entire tube lengths using a pulley system operated from the furnace floor.

3.2.3 *Eddy Current Flow Detection*

This technique uses a higher frequency than is employed for measurement of magnetic permeability and permits direct detection of internal (mid-wall) discontinuities such as fissures. However, the non-homogenous character of grain structure in cast materials such as HK-40 produces a strong interference which masks the presence of cracking unless the cracks are quite close to the surface.

3.2.4 *Ultrasonic Flaw Detection*

A method of ultrasonic inspection based on the "through transmission" technique employing two crystals has proved reliable for detection of mid-wall fissuring. Equipment has been developed which permits scanning a 40 ft (12 m) tube in about 10 minutes including set-up time.

3.2.5 *Radiographic Flaw Detection*

Radiography permits location of cracks or fissures in the tube wall; however, since radiography has a finite sensitivity the cracks must be sufficiently large in order to be detectable. Sensitivity may be reduced when the catalyst is in place. Also, nonradial crack orientation, characteristic in centrifugally cast HK-40 tubing material, creates detection problems. Radiography, though not practical for general tube scanning, has proved valuable as a means of confirming localized indications provided by other scanning methods.

3.2.6 *Television Flaw Detection*

Scanning of inside tube surfaces by closed circuit TV is practical and has application in certain cases. It is not, however, considered a generally applicable method for regular turnaround inspection programs because it requires removal of the catalyst. In addition, it allows detection of corrosion or cracking only on the inside surfaces, and provides no indication of mid-wall conditions.

3.2.7 *Dye Penetrant Flaw Detection*

Standard dye penetrant techniques using either fluorescent or red dye are useful for detection of cracks in or adjacent to welds in reformer tubes, manifolds, pigtail connections, etc.

4.0 REFERENCES

4.1 FM Global

Data Sheet 6-10, *Process Furnaces*.

Data Sheet 7-94/12-22, *Ammonia Synthesis Units*.

Data Sheet 12-14, *Waste Heat Boilers*.

Data Sheet 12-17, *Watertube Boilers*.

Data Sheet 17-1, *Nondestructive Examination*.

4.2 Other

ASME Boiler and Pressure Vessel Code, Section II, Materials.

ASME Boiler and Pressure Vessel Code, Section VIII, Rules for Construction of Pressure Vessels.

APPENDIX A GLOSSARY OF TERMS

Reforming: the thermal or catalytic conversion of petroleum compounds into more volatile products. The conversion may include cracking, polymerization, dehydrogenation, and isomerization.

APPENDIX B DOCUMENT REVISION HISTORY

This data sheet was originally published in October 1981.

APPENDIX C DESCRIPTIVE INFORMATION

C.1 General

The necessity for increased agricultural production per acre, and the wide use of nitric acid, nylons, urea-base plastics, etc. has created a very heavy demand on the chemical industry to furnish increasing supplies of ammonia. Larger plants operating at higher temperatures and pressures have taxed construction materials and metallurgical know-how. The rapid growth in demand for ammonia has left little time to adequately test many of the materials being used in the harsh environment encountered during certain phases of the ammonia synthesis train. Of particular concern is the extremely high temperature involved in the reforming process to liberate free hydrogen from the feed stock.

In areas of the world where natural gas is in short supply the use of naptha, a petroleum refinery by-product, is coming into prominence as feed stock and reformer furnace fuel. Data on special problems with the use of naphtha will be published as accumulated.

Other hydrocarbon feed stocks less frequently used in the production of hydrogen are LPG (propane and butane), natural gasoline, fuel oil, and crude oil.

C.2 Description of the Reforming Process

Ammonia (NH_3) is a compound of nitrogen and hydrogen which does not occur naturally in significant quantities on this planet and hence must be synthesized. In a typical ammonia synthesis plant the sources of elements comprising the ammonia molecule are respectively:

1. Hydrogen from water (H_2O) and naturally occurring methane (CH_4) gas.
2. Nitrogen from the atmosphere.

In the steam-reforming process, natural gas (methane) is decomposed in the primary reformer with the aid of steam and heat in the presence of a nickel catalyst to separate the hydrogen as follows:

$$CH_4 + H_2O \rightarrow CO + 3H_2$$

The mixture of steam and desulfurized natural gas is compressed to approximately 500 psi (3447 kPa) and preheated to about 900°F (482°C). Partial reforming is accomplished as this mixture passes through the catalyst filled primary reformer tubes. The reforming process is endothermic. Heat is supplied by the burning of natural gas or oil in a refractory-lined furnace surrounding the reformer tubes. Temperatures in the reformer tubes may range as high as 1800°F (982°C).

The effluent gas leaving the primary reformer tubes is composed of varying percentages of unreformed methane (CH_4), hydrogen (H_2), carbon monoxide (CO), and carbon dioxide (CO_2). About 70% of the natural gas feed stock is converted to raw synthesis gas which enters the collection (outlet) headers at temperatures generally in excess of 1400°F (760°C). Risers from the collection headers connect into an insulated and usually water-cooled transfer line through which the gas mixture passes to the secondary reformer. In the refractory-lined combustion chamber of the secondary reformer, preheated compressed air (the source of nitrogen) is introduced. The mixture then passes through a series of nickel catalyst beds. The reaction in this section is also endothermic. The heat required for this reaction is generated by combustion of the unreformed methane in the effluent from the primary reformer.

The reformed gas leaving the catalyst beds enters a quench section where water sprays reduce the gas temperature to about 500°F (260°C) and produce steam needed in the carbon monoxide (CO) shift converter. The reformed gas next enters the CO shift converter where it passes through an iron oxide catalyst bed. Reaction with steam converts the carbon monoxide in the gas stream to carbon dioxide and simultaneously produces more hydrogen. From the CO shift converter the gas mixture continues through the synthesis train to the eventual production of the ammonia product (see Data Sheet 7-94/12-22, *Ammonia Synthesis Units*).

C.3 Description of Primary Reformer

In older ammonia plants the primary reformer served several purposes. In addition to reforming the gas/steam mixture it was the heat source for preheating process air, process gas, and feedwater for the waste heat boiler, as well as superheating process steam.

In modern synthesis plants the reformer (Fig. 2) is only for reforming the gas/steam mixture. An auxiliary boiler, either gas or oil-fired, is employed to produce steam in the 1500 psi (10342 kPa) range for driving the system compressors. The auxiliary boiler is located immediately adjacent to the primary reformer and both are served by common forced draft (FD) and induced draft (ID) fans and combustion air preheater (see Figure 3).

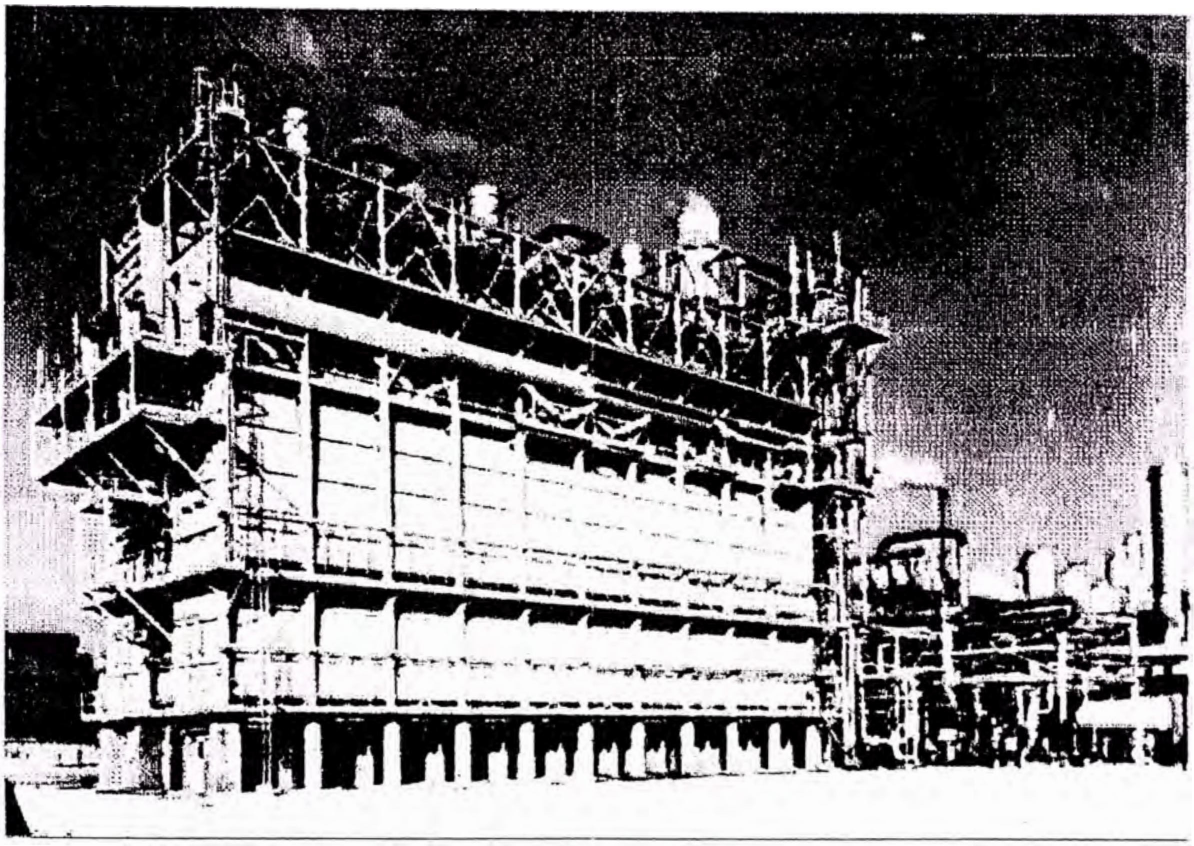

Fig. 2. Terrace wall primary reformer in modern ammonia synthesis plant. (Foster Wheeler Energy Corp.)

The convection section of the auxiliary boiler is the source of heat for superheating the high pressure steam and preheating process air to the secondary reformer, feedwater to the auxiliary and waste heat boilers, and the air/gas mixture to the primary reformer.

The process gas from the secondary reformer flows to the vertical U-tube "bayonet"-type waste heat boiler which is located downstream of the secondary reformer. The boiler recovers waste heat from the process gas. A cross section of the boiler is shown in Figure 3a. It is made up of an outer water jacket surrounding the shell. The shell is insulated internally and there is a protective shroud, usually made of a type of stainless steel, to separate the process gas from the insulation. The shroud is usually fabricated in sections and fitted together with slip joints. Conical gas shields are installed between the shell and the shroud to prevent gas leakage through the insulation.

The tube bundle is made up of "bayonet" and "scabbard" tubes. The "bayonet" tubes, approximately 1 in. (25 mm) O.D., are inserted into the "scabbard" tubes, approximately 2 in. (50 mm) O.D. The "bayonet" tubes supply the feedwater to the "scabbard tubes". The tube bundle also contains gas baffles to direct the flow of process gases over the surface of "scabbard" tubes. The entire tube bundle assembly is inserted into the gas space enclosed by the shroud.

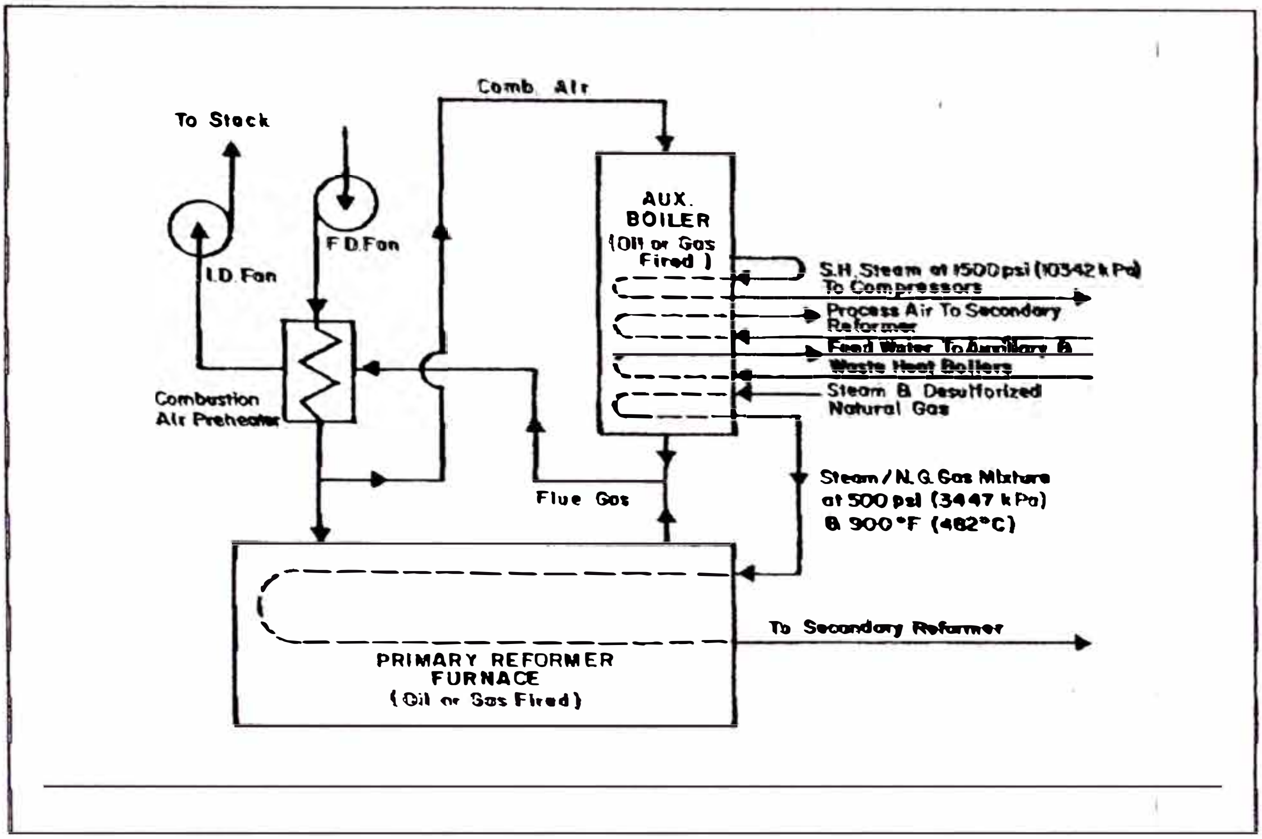

Fig. 3. Reformer & auxiliary boiler schematic.

For further information about waste heat boilers, refer to Data Sheet 12-14, *Waste Heat Boilers*, and about watertube boilers, to Data Sheet 12-17, *Watertube Boilers*.

The primary reformer consists of banks (sometimes referred to as "harps") of vertical tubes located in a refractory-lined furnace which is fired by natural gas. The shape of the furnace, the arrangement of the tube banks, and the positioning of the burners varies with the design. Figure 4 shows typical designs.

The reformer (or catalyst) tubes normally range from 2.5 in. (63.5 mm) to 5 in. (127 mm) inside diameter with wall thicknesses up to 1 in. (25.4 mm). Tube lengths range from 30 to 40 ft (9.1 to 12.2 m) or more and usually consist of 8 to 10 ft (2.4 to 3 m) sections welded together. The top ends are provided with either bolted or welded covers for loading the catalyst. The gas/steam mixture is introduced through flexible connectors near the top. In some designs the bottom ends of the tubes connect directly into the outlet manifolds (Fig. 5). Other designs provide outlet loops or pigtails to permit expansion and contraction of the tubes. Because of the considerable length of the reformer tubes and extreme variations from cold to operating temperatures, the design of suspension systems must take expansion into consideration. The methods preferred by most designers completely supports the tubes from the upper ends so that they are free to expand downward. Figure 6 is a schematic of such a system and Figure 7 shows details of the support assembly.

C.4 Reformer Materials

In most present installations, reformer tubes are of centrifugally cast HK-40 stainless steel. This is a high nickel/chromium alloy intended for high temperature and corrosive service. Other high nickel/chromium alloys are in use, primarily for tube to manifold connections, manifolds, risers, and transfer lines. The most common of these are Incoloy 800 (International Nickel Co.) and Supertherm (Abex Corp.). For reformer tubes, however, HK-40 stainless remains the workhorse of the industry. The chemical and physical properties of several reformer materials are shown in Table 1.

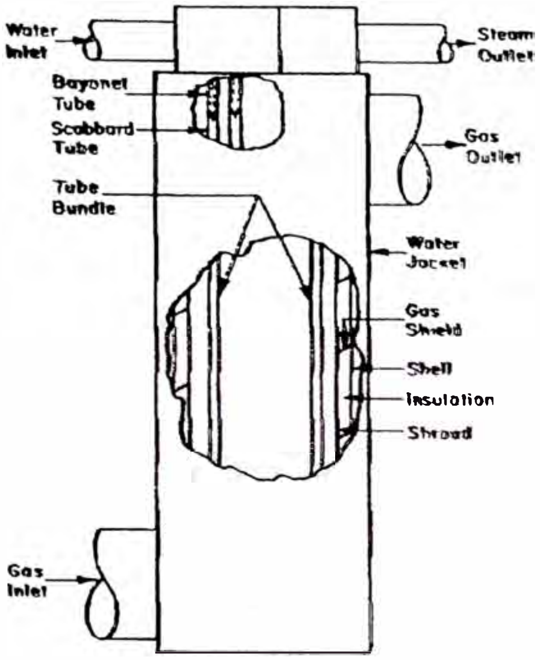

Fig. 3a. Vertical U-tube "bayonet"-type watertube boiler.

C.5 Characteristics of Reformer Tube Materials in High Temperature Service

HK-40. Reformer tubes of this material are subject to progressive deterioration which takes place throughout the thickness rather than from the surface. In the initial stages it can only be detected by metallographic examination. A phase change occurs in the material, rendering it brittle. It is evidenced by the slow formation of carbides, ferrite, and sigma (a very hard and brittle phase which occurs at the grain boundaries in steel alloys subjected to elevated temperatures for long periods) accompanied by loss of ductibility and creep of the material. The rate of formation varies with time and temperature. The critical temperature range appears to be between 1400°F (760°C) and 1600°F (871°C) but formation has taken place at lower and higher temperatures. Some success in restoring physical properties of HK-40 tubes has been achieved by periodic annealing treatments. This requires that the material be brought up to about 1950°F (1066°C) for a few minutes to dissolve the carbides and sigma; thus restoring the room temperature ductility.

The normal failure mode of HK-40 tubes is by longitudinal cracking or splitting which sometimes occurs after only two to three years of service. The failure is usually preceded by a change in the material from nonmagnetic to magnetic and is nearly always preceded by a measurable amount of creep evidenced by an increase in diameter.

Failure of HK-40 tubes also occurs, but with much less frequency, in two other modes.

1. Catastrophic oxidation. This is a rupture type of failure at a thinned area caused by localized internal corrosion. It is believed to be caused by an abnormality at the time of manufacture.

2. Weld cracking. This cracking occurs in or adjacent to circumferential welds in the tubes, usually in the hottest part of the furnace. They are generally considered to be caused by thermal stresses. It has been observed that such cracks often exist for years without completely penetrating the tube wall, which suggests that they are self-relieving.

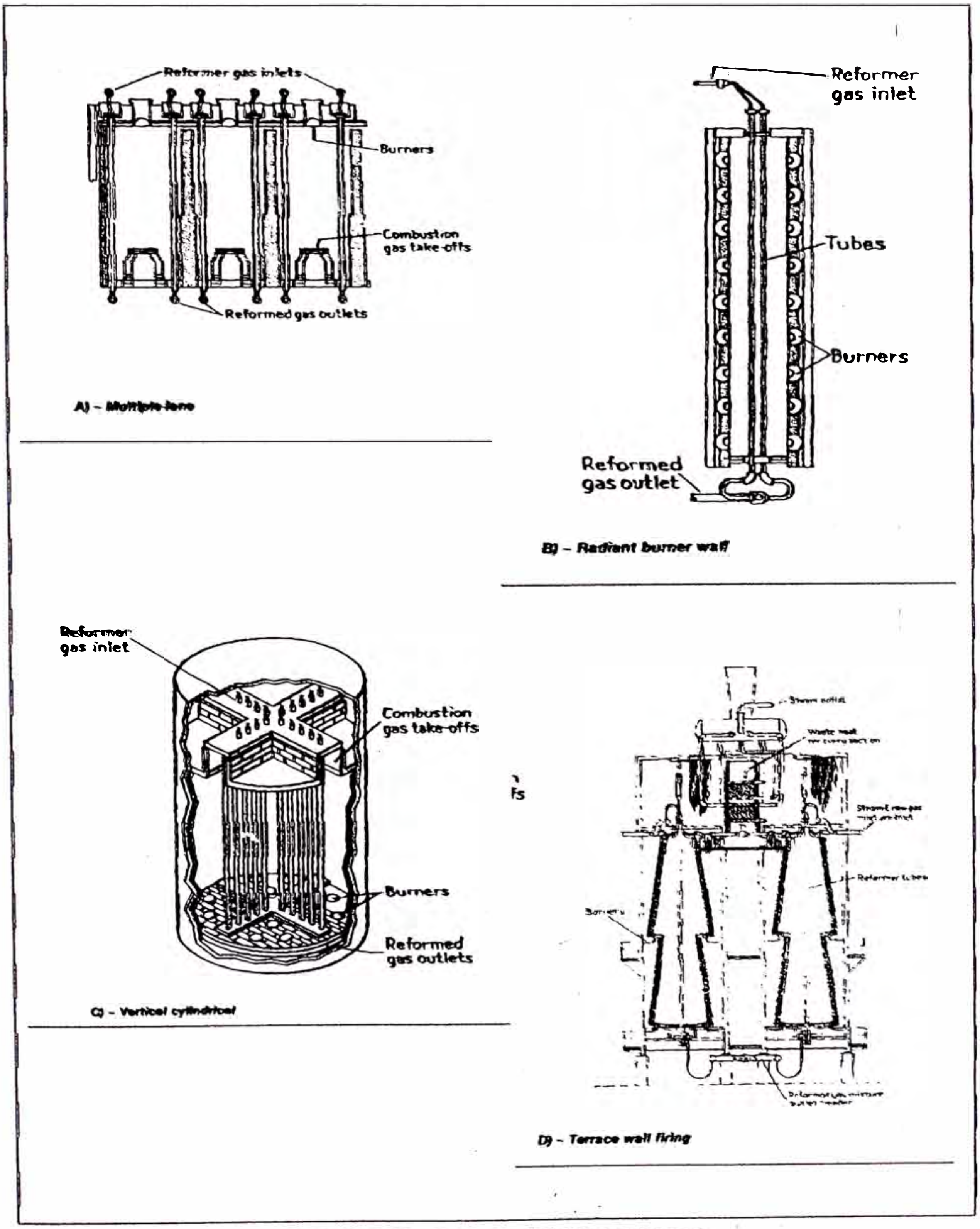

Fig. 4. Typical burner and catalyst tube arrangements.

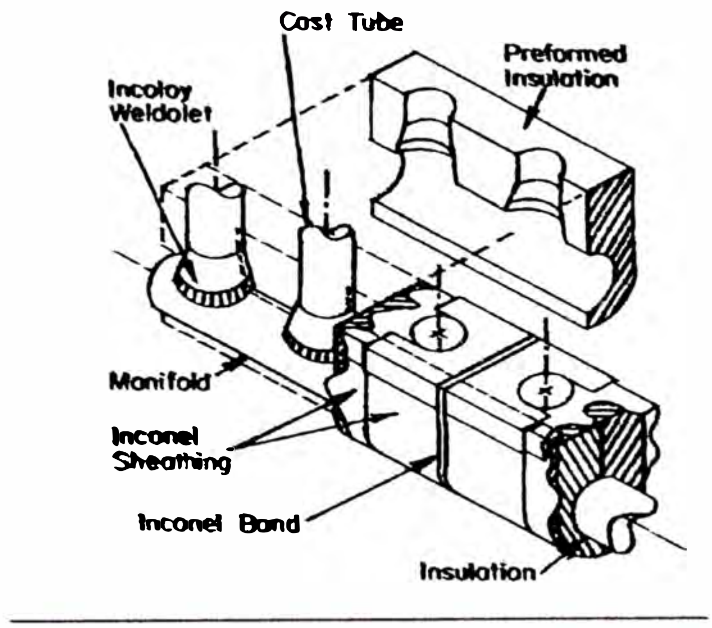

Fig. 5. Bottom manifold construction

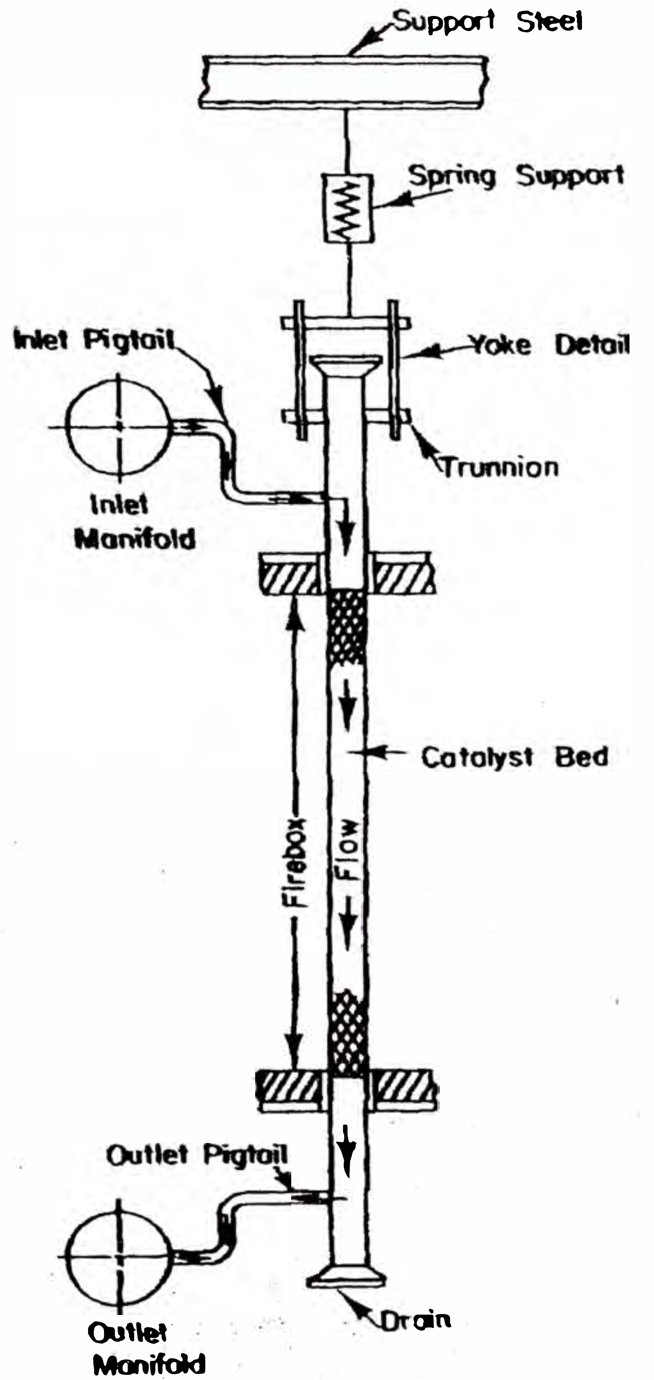

Fig. 6. Schematic of typical reformer tube completely supported from the upper end.

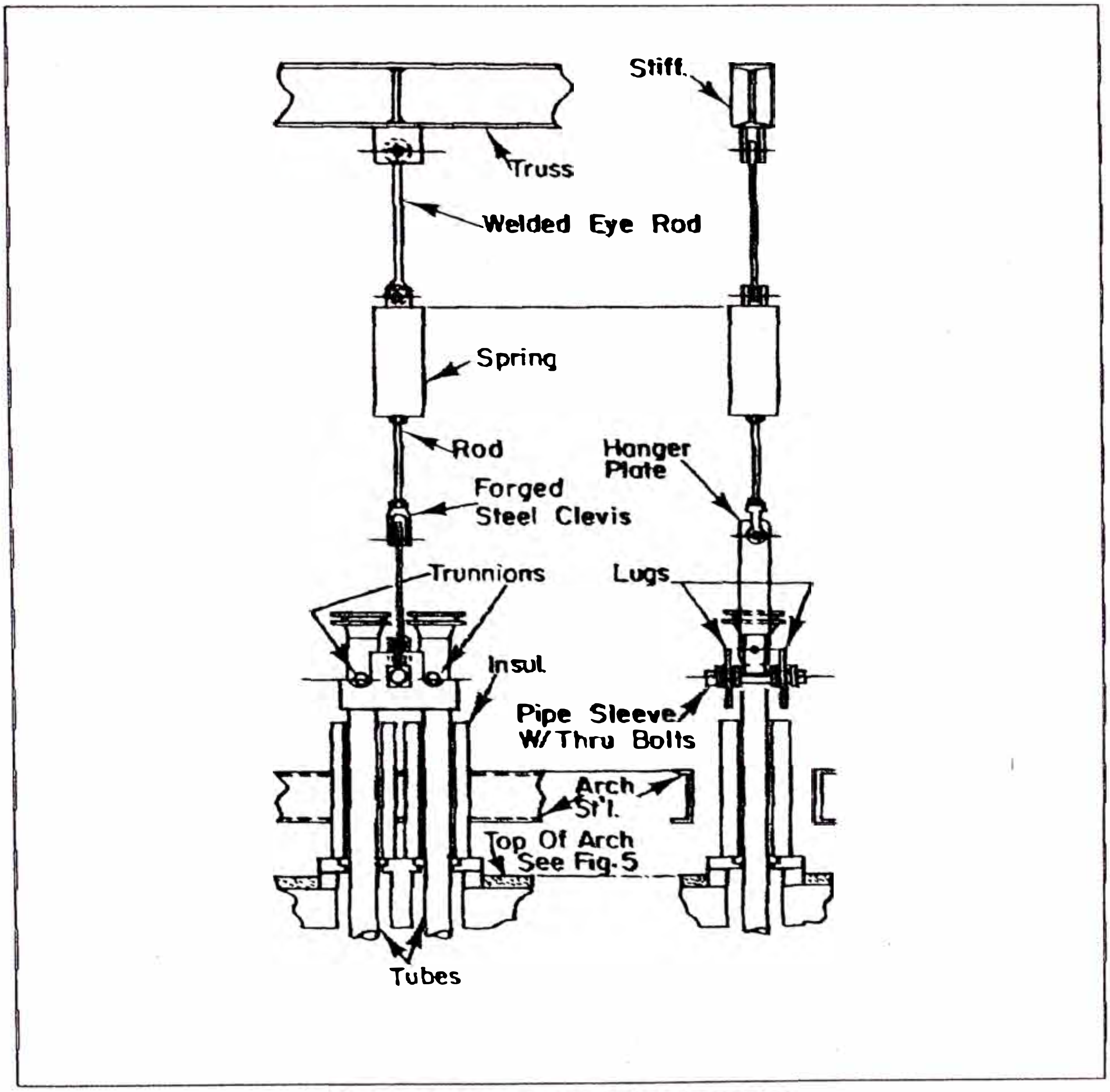

Fig. 7. Spring support assembly for reformer tubes.

Incoloy 800. Operating experience indicates that Incoloy 800 is better suited for reformers than HK-40; however, the usual choice of HK-40 over Incoloy is one of economics in initial cost. While some Incoloy 800 tubes have been in operation for over ten years, failures have been experienced in this material after less than two years of service. The type of deterioration to which this material is subject differs from that occurring in HK-40 in that it starts on the hot surface and progresses into the material. The defective areas are generally rather small, covering 4 to 8 in.^{2} (26 to 52 cm^2) and are difficult to detect by visual examination. Creep and/or change from nonmagnetic to magnetic condition are the major indications that the metal is deteriorating. Careful measurements of tube circumference should also reveal swelling. The amount of swelling due to creep varies with time, temperatures, and pressures to which the material has been subjected.

Metallographic examination of specimens removed from areas found to be magnetic, usually reveals a condition similar to oxidation. The surface appearance is practically unchanged and there is no noticeable reduction in thickness. The strength of the material, however, is seriously reduced. The microstructure at the interface between the magnetic material and the unaffected base metal will show an intercrystalline attack affecting the sound metal at the interfacing. These conditions are shown in Figure 8.

Unlike the deterioration taking place in HK-40, this damage is permanent and recovery by heat-treatment is impossible.

Table 1. Properties of Reformer Materials

	Incoloy 800 (1)	*H-30 (2)*	*HK-40 (2)*	*Super-Therm (3)*	*Paralloy CR 32 W (4)*
Carbon	0.10 max.	0.25-0.35	0.35-0.45	0.5 max.	0.10 max.
Manganese (max.)	1.50	1.50	1.50	0.7	1.0
Sulfur (max.)	0.03	0.04	0.04		0.03
Silicon (max.)	1.00	1.75	1.75	1.6	0.8
Copper (max.)	0.75				
Nickel	30-35	19-22	19-22	35	32
Chromium	19-23	23-27	23-27	26	20
Phosphorous		0.40	0.40		0.03
Cobalt				15	
Tungsten				5	
Niobium					1.3
Tensile strength (min) psi	75-100,000	65,000	62,500		76,000
Yield point (min) psi	25-50,000	35,000	35,000		30,000
Elongation (min) in 2 in.	50-30	10	10		32

(1) International Nickel Co. (Annealed)

(2) ASME Code, Sect. II A, SA 351

(3) ABEX Corp.

(4) APV Paramount Ltd. (Used primarily for Outlet Manifolds)

C.6 Description of Secondary Reformer

Figure 9 shows the general arrangement of a conventional secondary reformer. These vessels are usually built of carbon steel and in accordance with the ASME Construction Code, Section VIII. A castable refractory lining about 10 in. (254 mm) thick protects the shell (pressure boundary) from the internal temperature which may be in excess of 1600°F (870°C). Cooling water is circulated through a jacket that completely surrounds the pressure barrier. These units may typically range upward in size from 10 ft (3.05 m) in diameter and 25 ft (7.6 m) in height.

The usual modes of failure are cracking, bulging, or rupture of the shell or heads due to overheating as a result of deterioration of the refractory lining.

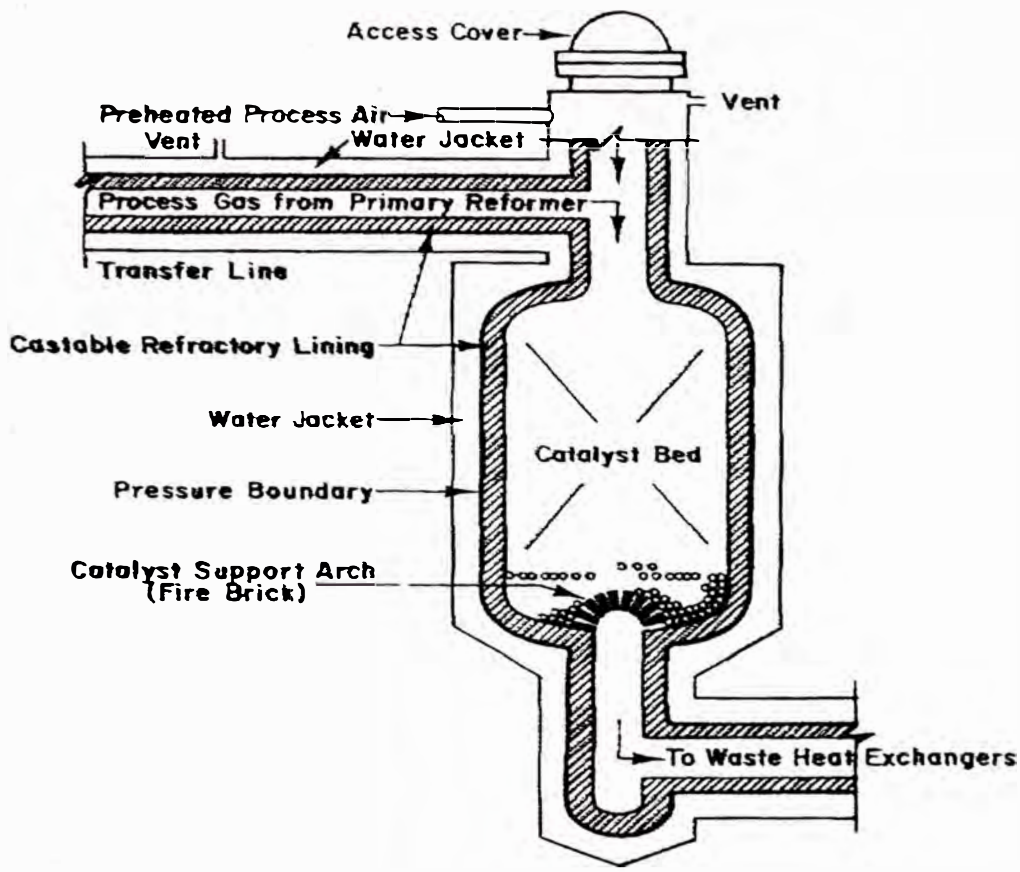

Fig. 9. Secondary reformer (General Arrangement).

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FIRE PROTECTION FOR GAS TURBINE INSTALLATIONS

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1.0 SCOPE

This data sheet addresses fire protection for combustion turbine installations. It contains recommendations to prevent and limit damage from fires and explosions internal and external to the turbine. Loss experience is summarized for both types of incidents. Additional information on protective equipment, monitoring, maintenance and testing of turbine safety equipment can be found in Data Sheet 13-17, *Gas Turbines*.

1.1 Changes

September 2002. New recommendation 2.2.1.3 has been included for combustible gas analyzers interlocked to shut down the turbine for enclosed gas-fired turbines. The recommendation for unenclosed combustion turbines had been changed to include gas turbines only.

2.0 LOSS PREVENTION RECOMMENDATIONS

This section provides general recommendations applying to all gas turbine installations and specific recommendations applying to enclosed installations, including skid-mounted package installations and installations in buildings without individual enclosures.

2.1 Construction and Location

2.1.1. Construct buildings of noncombustible or fire-resistant materials.

2.1.2 Provide two-hour rated fire proofing for structural steel used to support turbine, compressor, combustor and generator.

2.1.3 Provide drains, curbs or ramps for the gas turbine installation (including fuel and lube oil skids) to contain leaks. See Data Sheet 7-83, *Drainage Systems for Flammable Liquids*. The drainage system should be sized for the following:

a) Contents of the lube oil tank.

b) The maximum design discharge of the fixed fire suppression system for 10 minutes.

c) Hose stream demand for 10 minutes.

2.2 Protection

2.2.1 Enclosed Installations

Enclosed installations may be protected by total flooding fire protection systems. The use of FM Approved (see Appendix A for definition) fire resistant lubricants is an acceptable alternative.

2.2.1.1 Install Approved heat detectors at ceiling level of the gas turbine enclosure in accordance with Data Sheet 5-48, *Automatic Fire Detectors*. These detectors should alarm in a constantly attended area and should be interlocked to shutoff the fuel supply.

Base temperature rating of the detectors on the maximum operating temperature expected within the compartment. A common rating in the gas turbine, accessory , and generator compartments is 375°F (190°C). However, load compartments may require temperature ratings of up to 600°F (316°C).

2.2.1.2 Install Approved heat or flame detectors on both sides of the turbine if there is space below the turbine where lube oil or fuel oil can accumulate.

2.2.1.3 Provide combustible gas detection in gas turbine/combustor enclosures. Interlock the gas safety shutoff valve to close on detection of a gas leak.

2.2.1.4 Provide a fixed fire protection system for the gas turbine enclosure. The system should be designed to maintain an extinguishing concentration for a) the rundown time of the turbine and b) for the time turbine surfaces are above the autoignition temperature of the fluid whichever is longer. For lubricating oil autoignition temperatures are typically 700°F (371°C), for fuel oil autoignition temperatures are 500°F (260°C). A minimum time of 10 min should be used if rundown times are under 10 min The system should be automatically activated and capable of remote or manual operation from an accessible area. The fixed protection system may be one of the following:

- A carbon-dioxide extinguishing system designed in accordance with Data Sheet 4-11N, *Carbon-Dioxide Extinguishing Systems* and recommendation 2.2.1.5. Gas concentrations should be 34% by volume in one minute and 30% for the rundown time of the turbine (see Fig. 1).
- An Approved water mist system installed in accordance with manufacturer's installation instructions, NFPA 750, *Standard for the Installation of Water Mist Fire Protection Systems* and recommendation 2.2.1.6 (see Fig. 1).
- An Approved clean agent fire-extinguishing system installed in accordance with the manufacturer's instructions and NFPA 2001, *Clean Agent Fire Extinguishing Systems* and recommendation 2.2.1.5 (see Fig. 1).
- Where an existing installation is protected with a Halon 1301 extinguishing system it should be installed in accordance with NFPA 12A, *Halon 1301 Extinguishing Systems* and recommendation 2.2.1.5.
- An automatic sprinkler or water spray system installed in accordance with Data Sheet 2-8N, *Installation of Sprinkler Systems* or Data Sheet 4-1N , *Water Spray Fixed Systems* and recommendation 2.2.1.7 (see Fig. 1).
- If less flammable, Approved lubricants and hydraulics fluids are used, protection is not needed for lubrication and hydraulic systems. If liquid fuel is used provide detection and fixed protection for areas under the gas turbine.

2.2.1.5 **Where a gas agent is used:**

- Provide sufficient agent to produce an extinguishing concentration in one minute. Also provide an extended discharge to compensate for leakage from the compartment and maintain an extinguishing concentration for the rundown time of the turbine. A minimum time of 10 minutes or the actual rundown time of the turbine whichever is greater should be used.
- Conduct a full discharge test to verify that extinguishing concentrations can be maintained for the rundown time of the turbine. If this test has not been conducted, the system should not be considered reliable.
- Interlock the compartment ventilation system to shutoff on system discharge. Also provide automatic closing doors or dampers for openings not normally closed.

2.2.1.6 **Where water mist is used:**

- Design the system so that it will provide protection for 10 min or the rundown time of the turbine whichever is greater.
- Conduct a discharge test to verify that all nozzles flow free and clear.
- Interlock the compartment ventilation system to shutoff on system discharge. Also provide automatic closing doors or dampers for openings not normally closed.

2.2.1.7 **Where automatic sprinkler or water spray protection is used:**

- Install automatic sprinkler or water spray protection for exposed oil piping and areas on the floor under the turbine where lubricating oil or fuel oil may collect.
- Prevent direct water discharge onto hot surfaces such as exposed turbine casings.

2.2.2 *Unenclosed Gas Turbines*

Unenclosed gas turbines should be protected by local application systems for specific hazards such as bearing housings, lube oil tanks and fuel piping. Area protection should be provided for the building. The use of Approved fire resistant lubricants is an acceptable alternative for lubricating oil hazards.

2.2.2.1 Install Approved heat or flame detectors on both sides of the turbine if there is a space below the turbine where lube oil or fuel oil can accumulate.

2.2.2.2 Provide combustible gas detection over the combustor of gas fired units. Interlock the gas safety shut-off valve to close on detection of a gas leak.

2.2.2.3 Provide local application protection for bearing housings, lube oil tanks, hydraulic oil and seal oil systems. See recommendation 2.2.2.5 (see Fig. 2).

2.2.2.4 Install automatic sprinkler protection at ceiling level, see recommendation 2.2.2.7 (see Fig. 2).

2.2.2.7 Ceiling level protection systems should be designed to:

a) Provide 0.20 gpm/ft^2 (8 mm/min) over the most hydraulically remote 5,000 ft^2 (465 m^2) area, see Fig. 2.

b) Provide shielding or lagging over the turbine.

c) Allow 750 gpm (2800 dm^3/min) for hose streams.

d) Provide a water supply adequate for two hours.

2.2.2.8 Provide dry chemical and/or foam extinguisher adjacent to the gas turbine enclosure to extinguish small oil fires and insulation blanket fires.

2.3 Equipment and Processes

2.3.1 Prevention of Internal Fires and Explosions

2.3.1.1 Provide flame detectors in combustors interlocked to close a fuel shutoff valve in the event of flameout during operation. The time from flameout to complete cutoff of fuel should not exceed 750 milliseconds.

2.3.1.2 Provide redundant fuel shutoff valves in gaseous and liquid fuel systems. Provide a vent in gaseous systems, and a drain in liquid-fuel systems located between the valves. The vent or drain should open automatically on valve closure.

2.3.1.3 Install automatic drains in the combustor casings of gas turbines using liquid fuel. Test drains annually to ensure they operate properly.

2.3.1.4 Inspect the fuel system at least annually during regular combustion section inspections, as described in Data Sheet 13-17, *Gas Turbines*.

2.3.2 Fuel Supply

2.3.2.1 Arrange fuel oil supplies as recommended in Data Sheet 7-88, *Storage Tanks for Flammable Liquids*, Data Sheet 7-54, *Natural Gas and Gas Piping*, and Data Sheet 7-53, *Liquified Natural Gas*.

2.3.2.2 Arrange natural gas and natural gas piping in accordance with recommendations in Data Sheet 7-54, *Natural Gas and Gas Piping*.

2.3.2.3 Protect a vent to the outside for enclosures containing a gas pressure regulator.

2.3.2.4 Receivers if used should be designed, constructed and tested in accordance with the ASME Boiler and Pressure Vessel Code.

2.3.3 Piping

2.3.3.1 Install Approved shut-off valve(s) in the main gas and liquid fuel lines leading to the fuel manifolds on the gas turbine. Locate valves near the entrance to the turbine enclosure. The valve(s) should automatically close on fire detection or when the fire protection system operates. Valves should be operable from outside the fire area.

2.3.3.2 Provide a system to shut off hydraulic and lube-oil from the control room or other remote location in the event of fire.

2.3.3.3 Use Approved hydraulic fluids for hydraulic systems where possible. The fluid should be Approved for this application by the gas turbine manufacturer.

2.3.3.4 Provide metal guards for instrumentation in lubricating oil and fuel lines to prevent accidental breakage.

2.3.3.5 Use safety glass or similar impact-resistant material for windows in sight glasses.

2.3.3.6 Fabricate lubricating oil lines of pipe-guard (concentric pipes) construction (also known as safety piping) with the pressure line running inside the drain line.

2.3.3.7 Support rigid piping connected directly to the turbine so that failures will not occur from coincidence of the natural frequency of the piping with the rotational speed of the combustion turbine

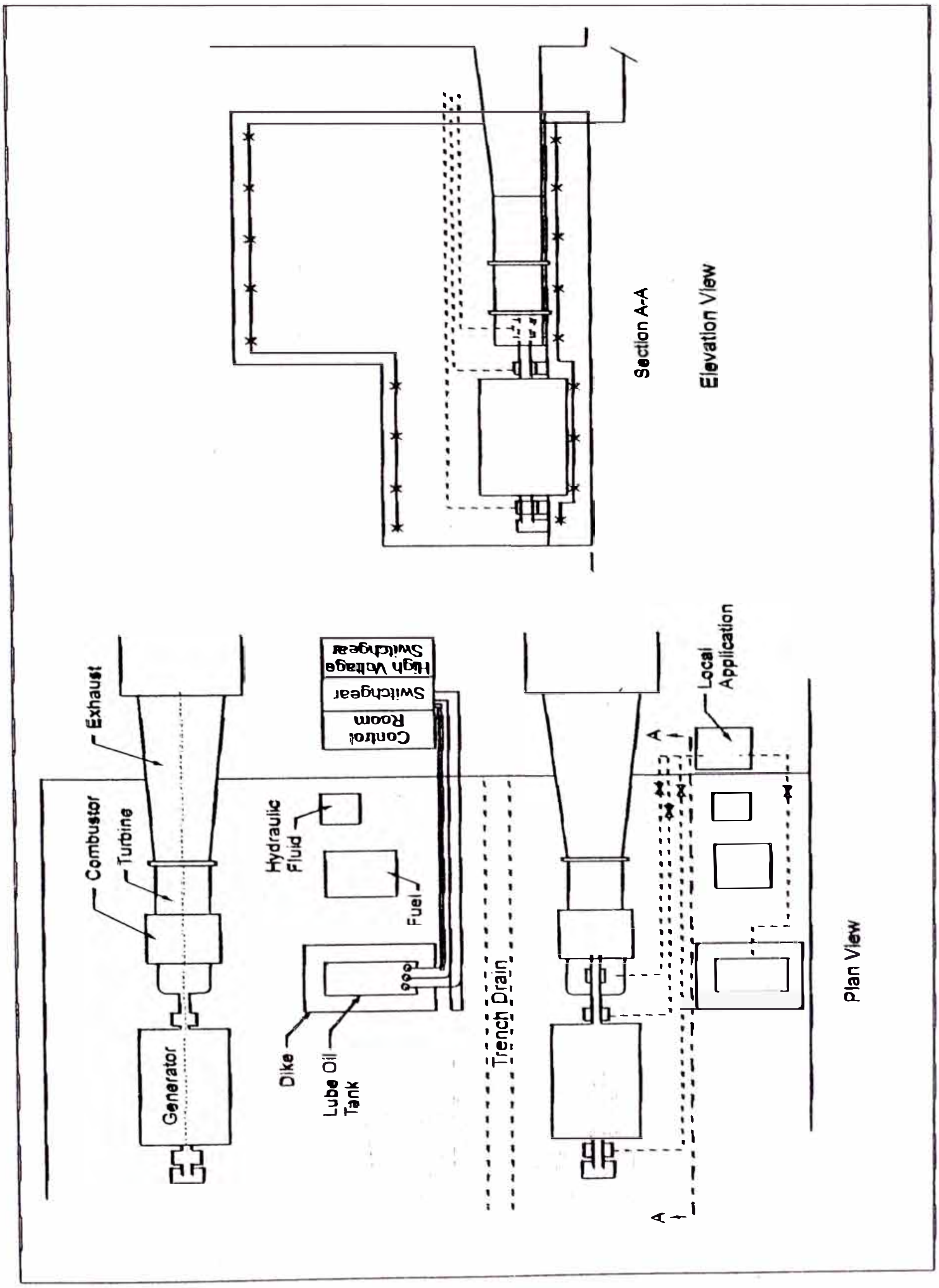

Fig. 2. Protection for unenclosed gas turbine.

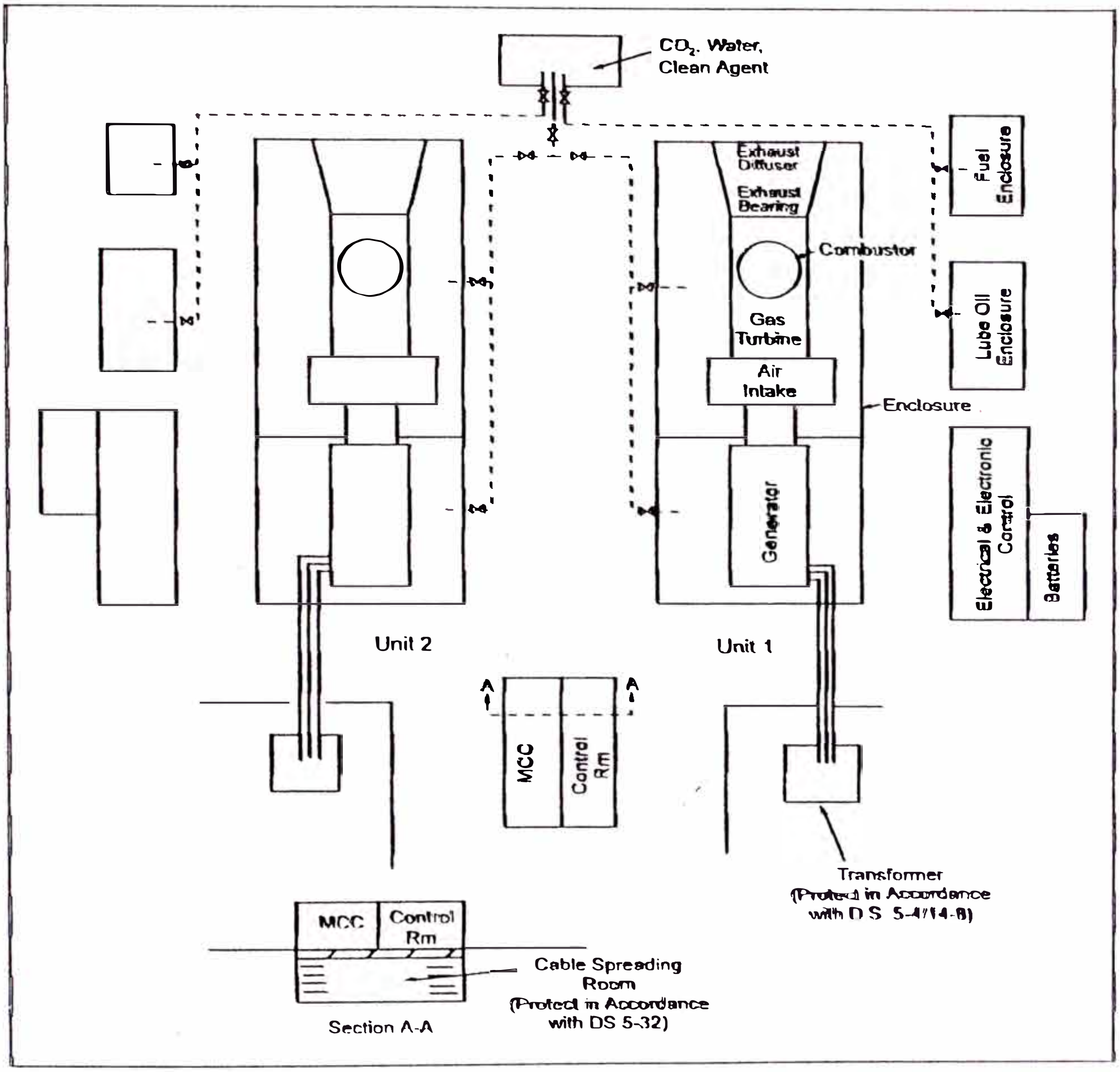

Fig. 1. Enclosed gas turbine protection system.

2.2.2.5 If less flammable, Approved lubricants and hydraulic fluids are used protection is not needed for lubrication and hydraulic systems.

- The fluid should be Approved for use by the gas turbine manufacturer.
- If liquid fuel is used provide detection and fixed protection for areas under the gas turbine.

2.2.2.6 Local application protection system may be water mist, automatic sprinkler or automatic water spray protection.

Automatic sprinklers or water spray should be:

- FM Approved
- Installed in accordance with Data Sheet 2-8N, *Installation of Sprinkler Systems* or Data Sheet 4-1N, *Water Spray Fixed Systems*
- Designed to flow 30 gpm (113 dm^3/min) per head

2.2.2.7 Ceiling level protection systems should be designed to:

a) Provide 0.20 gpm/ft^2 (8 mm/min) over the most hydraulically remote 5,000 ft^2 (465 m^2) area, see Fig. 2.

b) Provide shielding or lagging over the turbine.

c) Allow 750 gpm (2800 dm^3/min) for hose streams.

d) Provide a water supply adequate for two hours.

2.2.2.8 Provide dry chemical and/or foam extinguisher adjacent to the gas turbine enclosure to extinguish small oil fires and insulation blanket fires.

2.3 Equipment and Processes

2.3.1 Prevention of Internal Fires and Explosions

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2.3.1.2 Provide redundant fuel shutoff valves in gaseous and liquid fuel systems. Provide a vent in gaseous systems, and a drain in liquid-fuel systems located between the valves. The vent or drain should open automatically on valve closure.

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2.3.3.2 Provide a system to shut off hydraulic and lube-oil from the control room or other remote location in the event of fire.

2.3.3.3 Use Approved hydraulic fluids for hydraulic systems where possible. The fluid should be Approved for this application by the gas turbine manufacturer.

2.3.3.4 Provide metal guards for instrumentation in lubricating oil and fuel lines to prevent accidental breakage.

2.3.3.5 Use safety glass or similar impact-resistant material for windows in sight glasses.

2.3.3.6 Fabricate lubricating oil lines of pipe-guard (concentric pipes) construction (also known as safety piping) with the pressure line running inside the drain line.

2.3.3.7 Support rigid piping connected directly to the turbine so that failures will not occur from coincidence of the natural frequency of the piping with the rotational speed of the combustion turbine

2.3.3.8 Use welded pipe joints where practical. Use a torque wrench to assemble threaded couplings and flange bolts in fuel and oil piping. Torque the couplings and bolts to the manufacturer's recommendations. Provide positive locking devices to prevent unscrewing of fittings.

2.3.4 *Electrical*

2.3.4.1 Route instrumentation and control cable where possible, through areas where they would not be exposed by a fire.

2.3.4.2 Protect one set of control and power cables to ac and dc lubricating oil pumps with an Approved one hour firewrap.

2.3.4.3 Protect cable spreading rooms in accordance with the recommendations in Data Sheet 5-31, *Cables and Bus Bars*; protect switchgear and motor control centers in accordance with the recommendations in Data Sheet 5-19, *Switchgear and Circuit Breakers*; control rooms in accordance with the recommendations in Data Sheet 5-32, *Electronic Data Processing Systems*.

2.3.4.4 Protect transformer in accordance with Data Sheet 5-4, *Transformers*.

2.3.5 *Hydrogen*

2.3.5.1 Store cylinders outside or in a separate, well ventilated enclosure when possible.

2.3.5.2 Protect indoor storage of hydrogen cylinders with automatic sprinkler or water spray protection at a density of 0.25 gpm/ft^2 (10 mm/min) over and for 20 ft (6.1 m) beyond.

2.3.5.3 Other provisions contained in Data Sheet 7-91, *Hydrogen* , should be followed.

2.3.5.4 Install an excess flow valve and an emergency shutoff valve on the supply line where hydrogen is supplied from a large central storage remote from the building. The emergency shutoff valve should be at readily accessible location and arranged for remote operation from the control room.

2.3.5.5 Provide a means of venting and purging hydrogen cooled generators. Valve(s) should be remotely operable from the control room or accessible during a fire.

2.3.5.6 Provide a procedure to be followed regarding purging hydrogen from the generator when maintenance work is to be done.

2.3.6 *Air Filters*

2.3.6.1 Use noncombustible air filters where possible.

2.3.6.2 Provide access doors or hatches in inlet air-filter enclosures using combustible filters.

2.3.6.3 Provide manual firefighting equipment for personnel performing maintenance on air filters.

2.3.7 *Enclosure Ventilation*

Provide chain or shaft driven ventilation fans for enclosed installation ventilation. This reduces the possibility of damage to motors in event of exhaust seal leaks and reduces the need for operators to leave compartment doors open. This should improve gaseous system reliability.

2.3.8 *Heat Recovery Steam Generator Systems*

Follow recommendations contained in NFPA 85, *Boiler and Combustion Systems Hazards Code*, for combined cycle plants using HRSG.

2.4 Operations and Maintenance

2.4.1 Develop an inspection program listing enclosure openings such as doors, panels, dampers, etc. and enclosure ventilation system interlocks.

2.4.2 Inspect enclosure openings monthly to verify they are closed or will close automatically. Test ventilation system interlock annually to verify proper operation.

2.5 Contingency Planning

2.5.1 Develop a plant fire emergency plan so that fire departments are familiar with the hazards and protection at the facility. The emergency plan should include information as to when it would be possible to shut off the flow of oil to the bearings. This is especially necessary for unprotected or partially protected buildings. The objective is to prevent major structural damage to the building housing the turbine.

3.0 SUPPORT FOR RECOMMENDATIONS

3.1 Loss History

3.1.1 External Fires

3.1.1.1 Summary of Experience External Fires

The reported loss experience to date is from external fires. External fire incidents generally involve lubricating oil and/or fuel systems. These fires occur outside the gas turbine and expose the turbine and enclosure. Table 1 shows location and system involved in 54 fire and explosion incidents. About half the incidents occurred in the turbine compartment. The lower value property losses involved bearing seal oil fires and insulation blanket fires. The higher value property losses involved leaks or breaks in lube oil or fuel lines. Gas line leaks or breaks generally resulted in an explosion followed by fire.

Six incidents occurred in the generator compartment. Two were an oil fires, four were electrical fires involving the bus duct or collector area. The frequency of an oil fire in the generator compartment is low compared with the turbine end the combustor. However, protection is needed for this area.

Most installations were provided with a fixed protection system. The most commonly used systems were carbon dioxide and Halon 1301. Dry chemical systems were also used. Table 2 cites the reason protection systems were not effective.

Table 1. Summary of 54 external fire losses in gas turbine installations (1970–1978) by location and system involved

Location	System Involved			Total
	Lube-oil	Fuel (oil or gas)	Unknown	
Turbine compartment	14	15	2	31
Exhaust area	2	—	2	4
Load tunnel	1			1
Turning gear enclosure	2	—	—	2
Fuel system	—	3	—	3
Generator area	2	—	4	6
Unknown	4	2	3	9
Total	25	20	11	54

Table 2. Deficiencies of Gaseous Extinguishing Systems

Deficiency	No.
Doors or dampers not closed	3
Actuation system malfunction	3
System not in service	3
Fire not in protected area	4
Enclosure damaged by incident	2
Total	15

3.1.1.2 Gaseous Extinguishing Systems

The losses reported are helpful in determining what should be done to prevent protection system failures. Data does not include a number of fires in which the extinguishing system was successful in limiting damage. Many incidents are not reported because companies do not want to attract the attention of regulatory agencies or the incident was below the deductible.

A survey was conducted in 1999 concerning experience with CO_2 systems over the last few years. The survey involved fire protection engineers responsible for 90 gas turbine installations protected by CO_2 systems. Three fires were reported. Two fires involved fuel oil and one involved lube oil. The fires were extinguished by the CO_2 systems. A full discharge acceptance test had been conducted for these installations.

A gaseous agent system for a gas turbine installation should be installed with large enough diameter piping to permit changes in nozzle sizes. Following a full discharge test it may be necessary to increase the size of certain nozzles to obtain higher flow rates. This to maintain an extinguishing concentration for the initial discharge and/or rundown time of the turbine. A gaseous agent system should not be considered effective unless an acceptance test has been conducted with the gas turbine at operating temperature.

3.1.1.3 Water Mist (Fine Water-Spray) Systems

The phasing out of halon systems has led to the development of water mist systems. These systems extinguish fires by a combination of inerting and cooling. Inerting occurs when water mist is drawn into the fire with combustion air and turns to steam. The water mist also cools the flame and hot surfaces. There are several installations in the United States but no reported loss experience to date. Water mist systems were first used to protect gas turbine compartments in offshore oil platforms in the North Sea. There have been several fires. The systems have extinguished the fires successfully without damage to the turbine. Water mist systems are FM Approved as total flooding systems. Their use is limited to the volume and height of the enclosure given in the *Approval Guide*, a publication of FM Approvals. There are no systems Approved as local application systems.

3.1.2 Internal Fires and Explosions

Table 3 represents combined statistics from FM Global, Edison Electric Institute, and the NFPA.

Table 3. Internal fires and explosions (1970–1998)

Loss Causes	*Number of Losses*	Gross Property Damage Costs *(U.S. $1000's in 1999 dollars)*
Casing Drain Malfunction	5	$ 3490
Combustor Flameout	10	$ 9095
Ignition Failure	1	$ 1010
Leaking Fuel Valves and Fuel Switchover	8	$ 3470
Flashback, Foreign Liquid, Faulty Regulator, Etc.	9	$ 8064
Unknown	6	$ 7160
Total	39	$32,289

3.2 Illustrative Losses

3.2.1 External Fires and Explosions

3.2.1.1 Acceptance Test Detects Problem with CO_2 System

A high pressure CO_2 system was installed to protect four enclosed units at a large northeast utility. The turbines were rated at 50 MW(e). The CO_2 system was arranged with a selector valve so that the initial supply would discharge into the enclosure where the fire was detected. A full discharge acceptance test was conducted on Unit 4. A detector in Unit 4 was actuated to verify that interlocks would shut off the fuel supply and the exhaust system. In addition the CO_2 concentration for the rundown time of the turbine was to be measured. When the detector was activated the CO_2 system discharged into the Unit 4 enclosure, but the interlocks for fuel supply and exhaust air were improperly wired and shutdown Unit 3. Unit 4 fuel supply and exhaust continued to operate. CO_2 was exhausted from the enclosure. After the system was properly aligned another test was conducted. It was found that CO_2 concentrations could not be maintained for the rundown time of the turbine. If the test had not been conducted, two units would have been out of service in the event of fire in Unit 4.

3.2.1.2 CO_2 System Effectively Extinguishes a Fire

A 50 MW(e) gas turbine at a combined cycle plant was being started. Technicians had finished their work but had not tightened the fittings on the fuel nozzles when the unit was started. Oil leaked from the burner assemblies and an oil pool fire ignited under the gas turbine. Heat detectors activated the CO_2 system and the fire was extinguished with minimum damage.

3.2.1.3 Automatic Sprinkler Protection Effective in Preventing Major Building Damage.

An improved emergency response plan could have further reduced damage.

A prototype industrial gas turbine was undergoing test in the manufacturer's test facility. The building was 75 x 87 x 57 ft high (23 x 27 x 17 m). The walls were insulated metal panel on steel frame, and the roof was insulated steel deck on steel beams supported by steel truss. The building was sprinklered throughout by a system designed to provide 0.21 gpm/ft^2 (8.4 mm/min) over the most remote 2400 sq ft (223 m^2). Figure 3 is an elevation view of the building.

The gas turbine was a two-shaft machine with a power turbine cantilevered forward over two bearings housed in the load tunnel — the cavity inside the exhaust duct, through which the drive shaft passed. The drive shaft was coupled to a dynamometer.

An oil reservoir at the inlet end of the gas turbine, near the south wall, provided oil for lubrication and hydraulic control. A pump driven by the gas turbine shaft delivered 120 gpm (7.5 l/s) through pipes of up to 4 in. (10 cm) diameter to the three bearing sumps, including the sump in the load tunnel for Bearings 3 and 4. Pressure in the lines was regulated to 15 psi (103 kPa). During startup and shutdown a motor-driven auxiliary pump in the reservoir delivered oil at a rate of 25 gpm (1.5 l/s). An emergency pump driven by a battery-powered d.c. motor backed up the auxiliary pump.

The incident occurred when part of the rim of the power turbine disk fractured, releasing some of the blades. A blade jammed between the remaining blades and the casing, decelerating the rotor rapidly, and imparting a high transverse load to the bearings. This caused the cantilevered bearing housing to deflect shearing the flange bolts at both pressure and return lube-oil lines. (Fig. 4). Oil sprayed out the 3 in. (7.5 cm) pressure line and ignited.

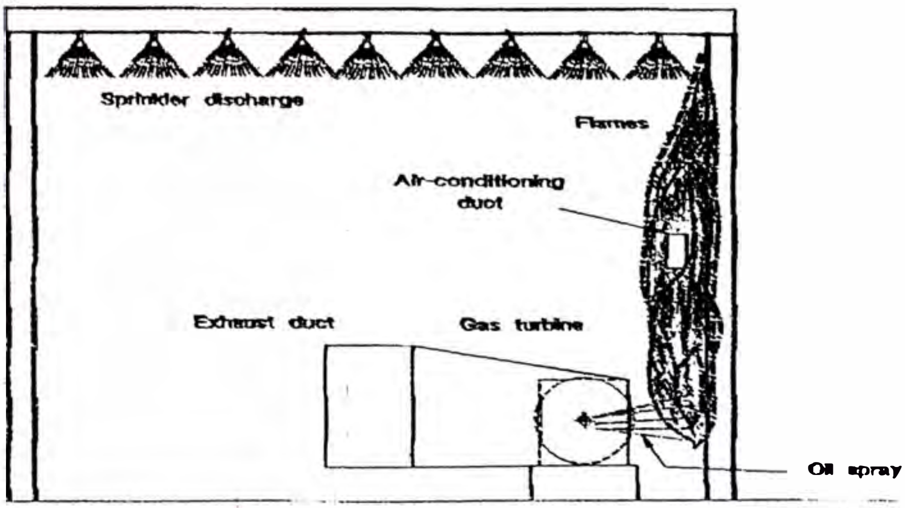

Fig. 3. Gas turbine facility fire.

The operator immediately tripped the gas turbine and it decelerated quickly to a stop. The a.c. lube oil pump continued to operate pumping oil through the separated line. When power to it was cut off, the d.c. pump started.

The public fire department arrived within five minutes and proceeded to fight the fire from outside. Heat from the fire opened all seventy-two sprinklers. The fire continued until an employee went into the building and shut off the emergency lube pump, cutting off the fuel supply.

Sprinkler discharge will not extinguish a spray fire. However, it will greatly limit damage to the building. The spray fire was extinguished by shutting off the source of fuel. Sprinklers were effective in preventing major structural damage to the building. In similar fires without sprinkler protection the building roof has collapsed.

3.2.2 *Internal Fires and Explosions*

The following case histories illustrate the major categories of internal fires and explosions that have occurred in the turbine combustor or compressor. Each case history discusses the approach to avoiding that particular hazard.

3.2.2.1 Internal Fire due to a Leaking Fuel Valve

A single-shaft gas turbine driving a standby generator in a public utility had been started up and warmed prior to loading. Before it was loaded, the dispatcher canceled the request, and it was shut down. Before the shutdown sequence was completed, attempts were made to restart the engine, but it would not respond. When the gas turbine was opened and examined, the turbine section was found completely burned out. Rotating and stationary components of the turbine section were severely damaged (Figs. 5 and 6).

The leading edges of first stage nozzles exhibited light damage, possibly unrelated to the fire. But the trailing edges were extensively burned. A torch-like flame severed almost all of the second and third stage nozzles: the second stage at midspan, and the third stage at the outer flow path. Apparently the flame front had been positioned halfway through the first stage nozzle row.

Nothing in the control logic could explain the development of the internal fire; it should have been impossible to inject fuel into the engine during the restart attempt before the igniter was activated. However, the fuel flow was governed by a throttle valve, an overspeed trip valve, and the fuel isolation valve, all downstream of the fuel pump. The overspeed trip valve was normally open. The function of the isolation valve was to shut off the liquid fuel during normal shutdown, and while the turbine was operating on the alternate fuel. This valve was air-tested after the loss, and it leaked. It was concluded that liquid fuel was forced through this leaking valve by the motor-driven fuel pump upon startup, and the pressure was sufficient to atomize the fuel as it flowed through the fuel nozzles into the hot combustion chambers. The fuel ignited and burned in a controlled manner in the turbine section.

Newer gas turbines often employ a double valve system for the gaseous fuel. Figure 7 is a schematic of a double valve arrangement with a solenoid-operated vent valve to bleed off any fuel trapped between the primary and secondary valves. This vent valve is closed during operation and is opened when the primary fuel valve closes on shutdown. In the system shown, the secondary valve is closed by differential pressure as the vent valve opens. In other systems the primary and secondary valves are closed by the control system.

Liquid-fuel systems often do not have a double valve arrangement. In one installation, the control valve serves as a shutoff valve. In this case the main fuel pump is turbine driven, and ceases to produce fuel pressure when the turbine decelerates. This may be sufficient protection against an internal fire after shutdown or just before startup.

The system in this case history has a solenoid-operated shutoff valve downstream of the control valve, and the main fuel pump is motor-driven. There is the potential for an internal fire if the shutoff or isolation valve leaks and if the turbine is started hot or the pump continues to operate after shutdown.

The case history shows it is important to provide double fuel valves in liquid fuel systems with motor-driven fuel pumps. The combustor drain is not sufficient protection against a leaking valve through which fuel can be sprayed under maximum fuel-pump pressure.

3.2.2.2 Internal Explosion due to Slow Response of the Fuel Valve to Flameout.

A gas turbine with a vertical combustor discharging through a U-duct into the turbine had been started on liquid fuel and synchronized. Steam was being injected through ports around the combustor fuel-nozzle for

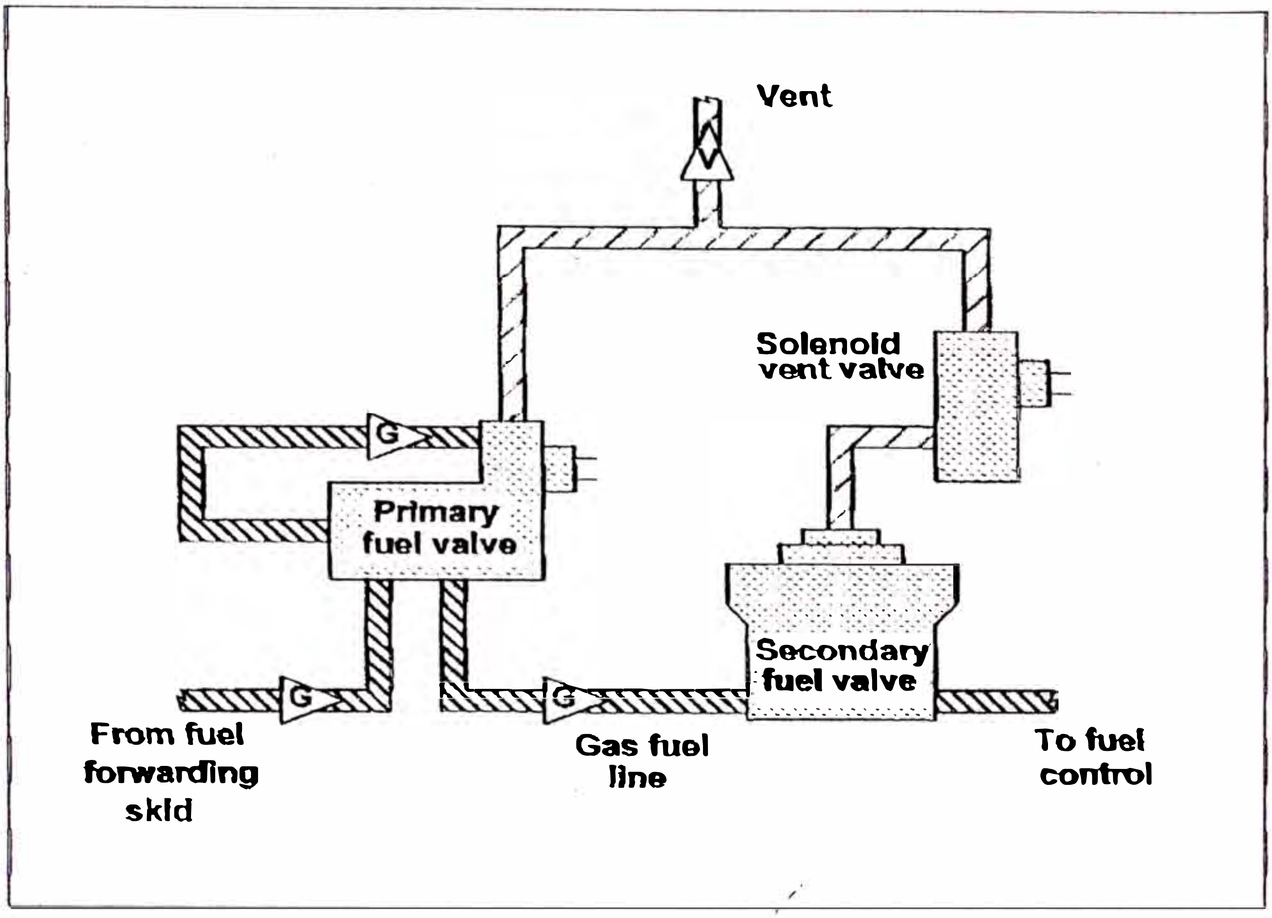

Fig. 7. Gaseous fuel valves. (Solar Turbines, Inc.)

emissions control. About twenty minutes after the initial injection of steam, a violent explosion took place in the combustor. At the same time, a number of alarms, including a flameout alarm, sounded.

The internal damage in the gas turbine was extensive. The combustor itself was not extensively damaged, but the ⅜ in (10 mm) thick internal liner of the U-tube was torn, with sections completely broken away. The first two rows of turbine blades were completely sheared off at the roots, and stationary nozzle vanes were broken and damaged. Downstream blades were badly fragmented from impact. Flange bolts on the engine casing were broken, and the flanges bent and separated.

Apparently the introduction of steam around the fuel nozzle resulted in a flameout. Flame detectors had been installed to sense flameout and to cut off the fuel supply. However, a time delay of 3.5 seconds was built into the shutoff sequence to give the fuel control time to react to underspeed conditions and avoid spurious trips. After the flameout, fuel continued to flow into the hot combustor, and reignited, probably at the discharge from the combustor, and in the U-tube. Internal fires and explosions resulting from flameout during normal operation can be prevented by rapid cutoff of fuel to the combustor after flameout.

3.2.2.3 Internal Fire due to a Faulty Casing Drain.

A third hazard of internal fire arises when liquid fuel collects in the bottom of the combustor casing after a shutdown and is not drained off, possibly because of drain malfunction. This pool of liquid fuel is ignited by the hot gases developed in a combustor during a subsequent startup.

A large industrial gas turbine-generator fueled by No. 2 fuel oil had been started and was being loaded when it tripped out on overspeed. It was idle for two hours while the control system was checked out. It was found that the overspeed trip resulted from a control malfunction, and the turbine was restarted. Within a few minutes, the gas turbine tripped on high exhaust temperature, and the exhaust stack began to emit dense black smoke. The exit gas temperature (EGT) reached 1200°F (650°C), far in excess of the normal level of 700°F (370°C). An operator opened a door in the exhaust duct and saw a glow from within the turbine.

When the turbine was cooled down and dismantled, three of the sixteen combustor baskets were found extensively damaged. Large areas were missing. The edges of the baskets were curled inward; covered with scale, and solidified globules of metal adhered to the surface, indicating metal had melted. Another combustor basket was slightly damaged, but the remaining twelve were still serviceable. The first two rows of rotating turbine blading were extensively damaged, presumably by impact with the combustion baskets.

The three damaged combustor baskets were at the bottom of the casing (Fig. 8) where unburned liquid fuel tends to accumulate when a gas turbine is shut down. An automatic drain in the bottom of the casing should drain off this fuel oil after shutdown. This drain was found jammed shut and would not open under the spring load.

The cause of the damage was uncontrolled burning of fuel oil that had drained into the combustor casing after the engine had tripped on the spurious overspeed signal. The oil accumulated in the casing due to the jammed drain. The damage was limited to Combustors 9, 10 and 11, because the burning gases were drawn into the bleed opening by the air being bled from the combustor casing. The flame was thus drawn away from adjacent combustors (such as Nos. 7 and 8) leaving them undamaged. The dilution of these gases by the bleed air prevented additional heat damage in the bleed system.

Combustor cases should have automatic drains to remove accumulations of liquid fuel after shutdown. These valves may be pneumatically operated, held closed by compressor discharge air while the engine is operating, and opening under spring force upon loss of pneumatic pressure after shutdown. Automatic drain valves should be tested annually to insure proper performance.

3.2.2.4 Internal Fire Occurring during Switchover from One Type of Fuel to Another.

Fires and explosion sometimes occur during switchover from liquid to gaseous fuel, or vice versa. One cause may be inadequate control of the rates of reduction of flow of the original fuel and increase of flow of the new fuel. The original fuel may not be purged adequately, and uncontrolled combustion may occur. Uncontrolled combustion can also occur if the valve admitting the original fuel leaks, and the fuel continues to flow after the switchover is complete.

During the first startup after an inspection, a gas turbine generator having a dual fuel system was brought up to part load on liquid fuel. A changeover to butane gas was made. Within a few minutes, the fuel pressure dropped and an explosion occurred. Both turbine stages were badly damaged by impact with fragments originating in the combustor and passing downstream.

An investigation showed that a loose cap on one of the dual-fuel nozzles permitted liquid fuel to leak into the combustor. The excess fuel ignited in the combustor and the explosion occurred.

3.2.2.5 Maintenance and Inspection of Gas Turbine Fuel Systems

Three of the four incidents described could have been detected and damage prevented by proper inspection and maintenance procedures (the leaking valve, jammed combustor drain, and the cap on the dual-fuel nozzle).

Combustion-section inspections should include inspecting fuel nozzles, igniters and flame detectors. The last, in particular, are subject to moisture and dirt contamination that could prevent them from sensing absence of flame. Particular attention must be paid to sealing the quartz lenses. Gas valves, fuel-oil valves and dual-fuel check valves should also be inspected and leak-tested during combustion section inspections, and fuel manifold and combustion casing drain valves should be tested.

The turbine in the first incident was a standby unit used for few operating hours per year. Malfunction of the components of concern does not depend only on hours of operation; idle time may have just as much effect. Critical fuel system components in standby units should be inspected annually.

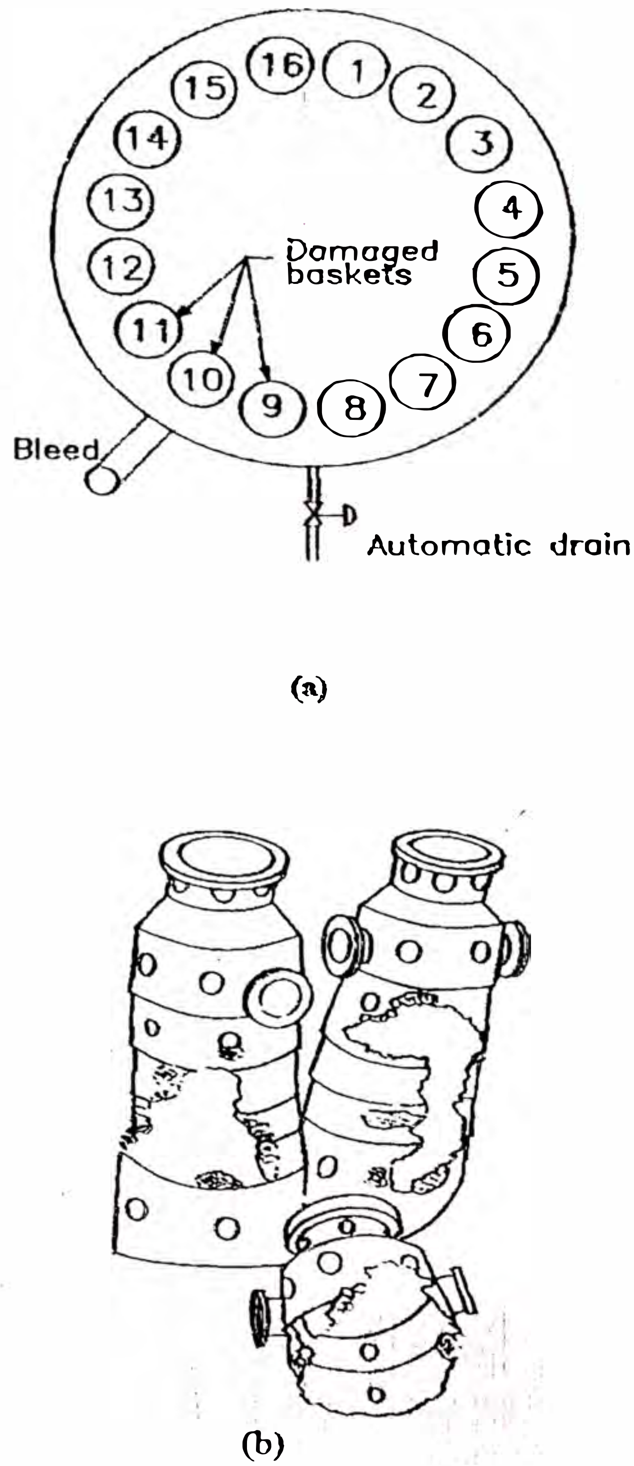

Fig. 8. Combustor damage due to pool fire in combustor casing.
(a) Arrangement of combustor baskets, looking rearward.
(b) Burned combustor baskets.

3.3 Test Data

3.3.1 Automatic sprinkler

FM Global Research conducted a series of tests for the United States Atomic Energy Commission (AEC). The results are contained in a report titled "Fire Tests of Automatic Sprinkler Protection for Oil Spill Fires", September 1957. The testing demonstrated automatic sprinklers were effective in controlling lubricating oil pool fires. It also showed they were effective in limiting heat damage to the building structure. Five tests, four pool fire tests and one combined spray and pool fire test was conducted. Automatic sprinkler protection at ceiling level quickly controlled pool oil fires. The oil spray fire continued to burn until the oil supply was shut off.

Four tests were conducted with 2,000 sq ft (185.9 sq m) of oil on the floor. The tests were intended to measure burning rate of oil and to determine whether ceiling level automatic sprinkler protection could control a fire in a large lubricating oil release. A fifth test was conducted. The test consisted of a steel column with a series of cross members at the 10 ft (3 m) and 20 ft (6 m) elevation. An oil spray nozzle was mounted 12 ft (3.7 m) above the floor, and 2 ft (0.6 m) from the vertical column on one of the crossbeams, as illustrated in Figure 9. Lubricating oil was pumped to the nozzle at a flow rate of 10.8 gpm (0.68 l/s) and was ignited; the figure shows the oil spray just prior to ignition. Thermocouples were mounted throughout the steel structure and at the roof level, 33 ft (10 m) above the floor. Sprinkler heads were mounted at the roof level at 10 ft (3.05 m) spacing, and were operated about 1 minute after ignition of the spray.

In the spray fire test, the sprinkler discharge density was increased to 0.36 gpm/ft^2 (14.4 mm/min). Thermocouples on an exposed steel column continued to register 1400-1800°F (760-983°C) over a period of 8 minutes, until the oil spray was shut off. At the same time, a thermocouple at roof level, at a point 14 ft (4.3 m) laterally from the ignition point, registered a temperature of 860°F (460°C). Ceiling temperatures would most probably have been similar to the free burn pool fire temperatures of 1600 to 1800°F (870 to 983°C). However, automatic sprinklers came on and with a sprinkler density of 0.20 gpm/ft^2 (8 mm/min) held the ceiling temperature to 750°F (400°C). As sprinkler density was increased the ceiling temperatures decreased further to 200°F (93°C).

Conclusions are as follows:

- Automatic sprinklers will extinguish an oil spill fire on the floor at a discharge density of 0.13 gpm/sq ft (5.2 mm/min) with some margin of safety.
- Automatic sprinklers will prevent damage to building columns from a floor spill fire. Without automatic sprinklers serious distortion and actual column failure would be expected in less than 10 minutes.
- Oil discharged as a spray may bring about failure of exposed steel near the fire. Automatic sprinklers may not extinguish a spray fire. However, automatic sprinklers will limit temperatures for structural steel and roof areas not immediately adjacent to the oil spray fire.

3.3.2 Water Discharge on Hot Gas Turbine Casings

An accidental water discharge on the hot casing of a gas turbine while it is operating may cause damage. A major loss involving such a discharge occurred when three accidental trips of a deluge system wetted the turbine casing of a heavy-duty gas turbine. The casing was operating at 550-600°F (288-316°C). The deluge nozzles were directed at the top of the turbine casing. No immediate damage was noted. However, it was noted that there was an increase in the exhaust gas temperature after each incident. Four months after these incidents the unit was shut down and the turbine section opened for inspection. The blades on both turbine stages were rubbed severely at their tips; the blades in the first stage were worn approximately 0.060 in. (1500 microns), while the blades of the second stage were worn a little less (0.050 in. or 1300 microns). The casing had distorted elastically as a result of the circumferentially-varying cooling effect of the deluge-system discharge. There was no permanent material damage to the casing, and dimensions were within blueprint limits after it returned to its original shape when the temperature gradients were removed. The company involved continues to use fixed automatic sprinkler system protection for their turbines. However, nozzles are arranged so that they do not spray onto the turbine casing.

Another accidental water discharge incident occurred to a 35 MW gas turbine without damage. The turbine was in operation when a 6 in. (15.2 cm) fitting between the sprinkler riser and the cross main separated. An estimated 1200 gpm of water discharged from the open fitting. The casing was insulated with lagging. The turbine tripped off line and coasted down with oil in the bearings. The turning gear breaker tripped and the

FM Global Research has completed an analytical study of the temperatures, stresses, and deflections of hot gas turbine casings subjected to sprinkler discharges of various densities and areas of impact. The casing involved in the first loss was used as a model for the study.

It was concluded that sprinkler water on a hot turbine casing will not cause stress beyond the yield point of the turbine casing material. It was also found that blade rubbing due to the decrease in clearance between the turbine casing and the blades can occur. The casing was approximated as a thin walled cylinder maintained at a constant temperature on its inner wall and cooled non-uniformly by sprinkler discharge on the outer surface[2].

As noted above water in contact with the turbine casing has sometimes caused blade rubbing. It is known that internal clearances are reduced when operating at higher power settings. For the purpose of FM Approval testing it was assumed that the allowable deflection due to cooling is proportional to the radius of the turbine casing for all classes of combustion turbines[3]. A representative value of the clearance between casing and the turbine blades is about 0.1% of the casing radius, when the turbine is under load[4]. At shut down the clearances increase substantially.

Testing was conducted to simulate water mist system discharge impinging on a hot turbine casing to determine whether a deflection greater than 0.1% of the turbine radius would occur. The simulation makes an allowance for dry spots on the casing, where cooling would not occur.

Water mist systems generally fall into two categories with regard to thermal impact. One category in which water from water mist nozzles is likely to come in contact with the turbine casing. A second type in which the water mist does not impinge on the turbine casing.

The testing for both types of water mist systems uses a horizontal steel plate 3.3 ft × 6.6 ft × 2 in. thick (1.0 m x2.0 m x 50 mm)to stimulate the turbine casing. Thermocouples are embedded in the plate at three depths: ½ in. (12.7 mm), 1 in. (25.4 mm), and 1 ½ in. (38.1 mm) below the surface. The water mist nozzles are located as close to the heated plate as allowed by the manufacturer's installation instructions. The plate is heated to a temperature of 570°F (300°C). The water mist system is discharged and temperatures are measured at the three depths over one extinguishment spray cycle. It is assumed that the top surface receives a constant cooling flux and that the bottom surface is adiabatic. Using the temperature distribution for the model, the deformation is calculated for a 2 in. (5 cm) thick casing, with a radius of 3.3 ft (1.0 m). The deformation cannot be greater than 0.1% of the turbine radius.

4.0 REFERENCES

Data Sheet 4-11N, *Water Spray Fixed Systems*.
Data Sheet 5-19, *Switchgear and Circuit Breakers*.
Data Sheet 5-31, *Cables and Bus Bars*.
Data Sheet 5-32, *Electronic Data Processing Systems*.
Data Sheet 5-48, *Automatic Fire Detectors*.
Data Sheet 7-54, *Natural Gas and Gas Piping*.
Data Sheet 7-83, *Drainage Systems for Flammable Liquids*.
Data Sheet 7-88, *Storage Tanks for Flammable Liquids*.
Data Sheet 7-91, *Hydrogen*.
Data Sheet 9-9/17-9, *Equipment Replacement Costs*.
Data Sheet 13-17, *Gas Turbines*.

4.2 NFPA Standards

NFPA 12A, *Halon 1301 Extinguishing Systems*.
NFPA 85, *Boiler and Combustion Systems Hazards Code*.
NFPA 750, *Standard for the Installation of Water Mist Fire Protection Systems*.
NFPA 2001, *Clean Agent Fire-Extinguishing Systems*.

APPENDIX A GLOSSARY OF TERMS

Approved: references to "Approved" in this data sheet means the product and services have satisfied the criteria for FM Approval. Refer to the *Approval Guide*, a publication of FM Approvals, for a complete listing of products and services that are FM Approved.

Enclosed installation: A gas turbine installation in which all major components and systems (except the driven machine) are housed in an enclosure. For larger units there could be several enclosures, one enclosure for each of the major systems. It is sometimes referred to as a package installation, because it is arranged on a structural skid for transportation as a unit.

Flameout: General loss of flame in a gas turbine combustor, possibly because of restriction in the fuel lines to the combustor section or a control malfunction that reduces fuel flow below the lower limit of combustion.

Fire or explosion:

External: A fire occurring outside the gas turbine. In most cases damage is to piping, cable or external surfaces of the turbine. The enclosure housing the turbine may also be damaged. Fires involve leaks of oil at bearing housings or insulation blanket fires are usually high value fires. Fires involving leaks or breaks in lube oil or fuel lines are usually high value fires. Gas line leaks or breaks generally result in an explosion followed by a fire.

Internal: A fire occurring inside one of the major components of the turbine usually due to fuel accumulations. Fuel may accumulate due to fuel leakage past shutoff valves, delay in shutdown following loss of flame, failure of a casing drain, or an inadequate purge. The fire or explosion occurs within the turbine, compressor or exhaust system.

Gaseous, total flooding system: A fire extinguishing system that relies on filling an enclosure with an extinguishing agent, and maintaining the extinguishing concentration within the enclosure until the fire is extinguished and conditions will not permit reignition.

Gas turbine installation: The arrangement of a gas turbine and its driven machine (usually an electric generator or compressor) in a facility. The installation is usually understood to include a lubrication system for the machinery bearings, a hydraulic system for certain control and protective functions, liquid fuel and gaseous fuel conditioning and delivery systems, a fire protection system, switchgear and a control room. The air intake and filter, including silencer and air cooling system, and the exhaust duct and silencer, are part of the installation.

Halocarbon clean agent: An extinguishing agent constituted of organic compounds containing fluorine, chlorine, bromine or iodine.

Inert gas clean agent: An extinguishing agent constituted of the inert gases argon, nitrogen, helium or neon. A blended agent may also include carbon dioxide.

Lagging: The term "lagging" refers to a covering or enclosure of some kind designed to shield the hot section of a gas turbine from external factors, such as other equipment, water discharge, or simply the environment, and to keep personnel from accidental contact with the hot section while the turbine is operating.

Lagging consists of insulating blankets around the casing. The insulation is usually metal covered.

Less flammable fluid: A lubricant or hydraulic fluid that is unable to stabilize a spray flame, and is classified as Group 1 according to the FM Specification *Test Standard for Flammability of Hydraulic Fluids Class 6930*. Mineral oil is classified as Group 3 according to this standard.

Skid: A structural steel base on which a gas turbine and/or its auxiliary components are mounted. It may be enclosed or unenclosed.

Unenclosed installation: A gas turbine installation, usually in a large building and possibly part of a multiple installation, without individual enclosures for any of its auxiliaries or components.

Water mist: A fire extinguishing system in which multiple spray nozzles discharge directional fine water sprays under high pressure, or by air atomization. The system produces significantly smaller water droplets than those generated by automatic sprinklers, and extinguish large fires (including spray fires) faster and more effectively. The smaller droplets vaporize and extract heat more rapidly from the flames.

APPENDIX B DOCUMENT REVISION HISTORY

May 2000. The following changes were made:

1. The recommendation for excess flow valves as an alternate form of protection to fixed fire protection has been removed. Excess flow valves function if the flow exceeds 110% of the rated flow. There have been large losses in which oil or fuel leakage from a flange or a fitting has been substantially less than the rated

flow. Excess flow valves may be of benefit in installations such as engine test cells where the frequency of a catastrophic event is substantially higher than in production machines.

2. A requirement for a full discharge trip test has been included for gaseous agent extinguishing systems. In addition an inspection program for doors and damper intended to seal openings is recommended. The causes of previous extinguishing system failures are reported. Also the results of a recent survey of loss prevention engineers specializing in fire protection for utilities indicate that the reliability of these systems is substantially improved when full discharge trip tests are conducted.

3. Protection of one set of control and power cable for ac and dc lube oil pumps is recommended.

4. Fixed fire protection system agent supply should be 10 min or the rundown time of the turbine for enclosed turbines whichever is greater. Local application system agent supply should be 20 min or the rundown time of the turbine whichever is greater.

5. Automatic sprinkler or water spray protection is recommended as an alternate form of protection providing the system is arranged to prevent water discharging onto the turbine casing.

6. An annual test frequency is recommended for automatic drains in combustor casings.

7. Descriptions of tests and losses involving automatic sprinkler protection have been revised and examples of the need to functionally test gaseous agent systems have been added.

The September 1998 revision recommended:

- The use of excess flow check valves in lubrication, hydraulic and liquid-fuel systems.
- Fine-water spray (FWS) extinguishing systems
- The use of less flammable lubricants and hydraulic fluids
- Direct fire protection of the main structural members of turbine halls.

APPENDIX C SUBJECT MATTER SECTION

C.1 Water Mist System

C.1.1 Description of Water Mist Systems

Water mist extinguishing systems can be used to protect gas turbines housed in enclosures. These enclosures have forced-draft ventilation systems. The ventilation system, ventilation openings, and doors should be closed before the system operates.

The suppression system consists of fine water spray nozzles, fire detection (heat or flame), a control panel, a water supply, and if necessary an air supply. The water and air can be supplied from cylinders or from the plant water and air system if quality is adequate. Figure 10 shows one Approved system. Heat detectors are installed at ceiling level and have a temperature rating above the normal operating temperature in the enclosure. Nozzles are installed on each side of the gas turbine. Branch lines are installed at the ceiling of the enclosure and 3 ft (0.9 m) above the floor. The latter set of nozzles is directed at fires under the turbine that may be shielded from overhead nozzles.

Figure 11 illustrates an arrangement of one water mist system showing water tank and air cylinders. The solenoid valve on the air cylinder is actuated by the fire detection system. Air then pressurizes the water tank to deliver water through the piping to the nozzles in the gas turbine enclosure. Additional air passes through the piping to the nozzles.

Figure 12 illustrates a twin fluid spray nozzle. Air discharges through the central orifice, while water discharges through the outer ring of orifices.

C.1.2 Requirements for Approval of a Water Mist System

An Approved water mist system will extinguish shielded and unshielded hydrocarbon pool and spray fires in enclosures not exceeding the volumes listed in the *Approval Guide*. The system is also tested to verify that the gas turbine casing will not be cooled an unacceptable amount. Blade rubbing which reduces the efficiency of a turbine can occur if water spray impinges directly on a hot casing during operation. Testing for blade rubbing is conducted as specified in 3.3.2.

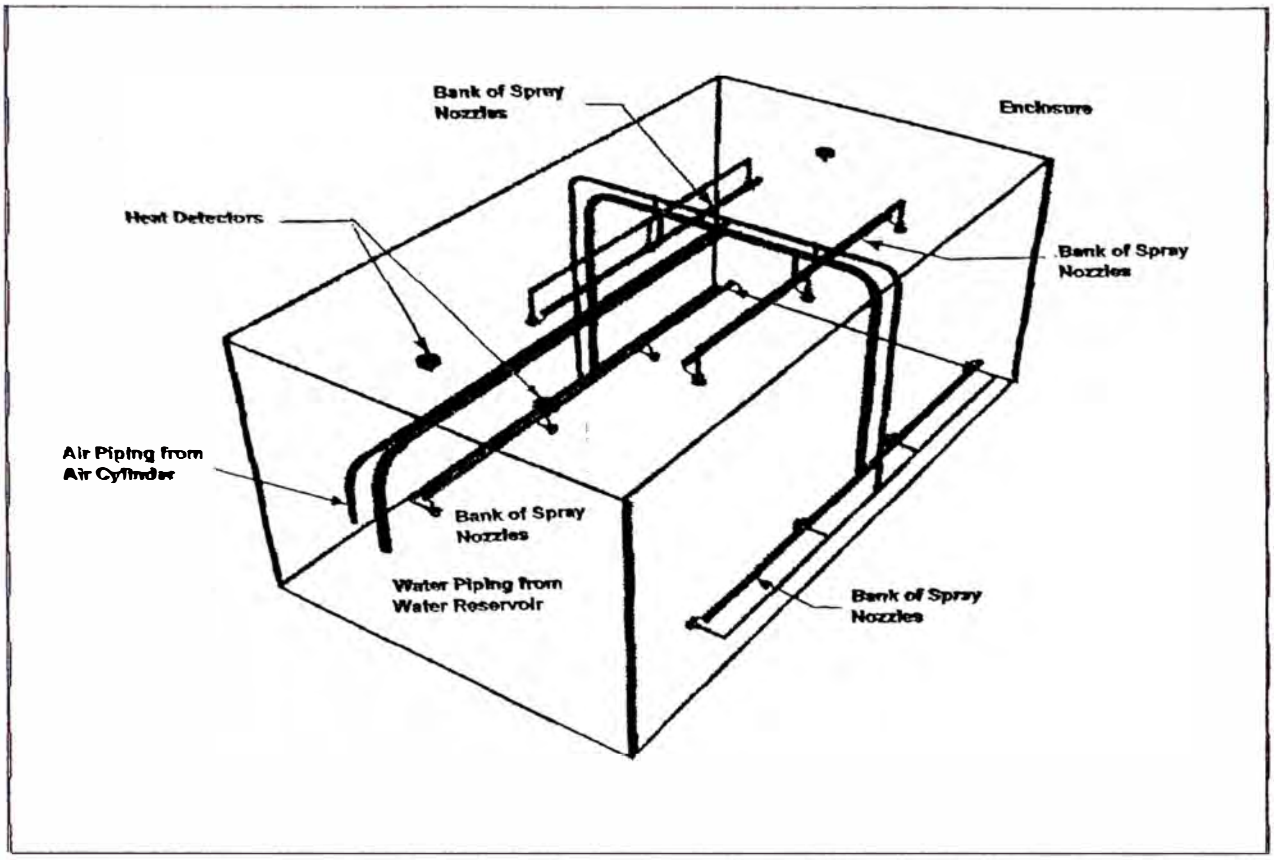

Fig. 10. Layout of heat detectors, air and water piping, and nozzles for one type of water mist system.

C.2 Rundown Time for Turbines

The fire protection system should maintain an extinguishing concentration for the rundown time of the turbine and the time it takes surfaces temperatures at full load to below the autoignition temperature of the oil. Rundown times depend on the type of turbine. Reported times have varied from 5 to 40 min Industrial turbines have longer rundown times than aeroderivative turbines. The larger the turbine the longer the rundown time. Also the higher the higher the load the turbine is under the longer the rundown time. The rundown time should be known before conducting a discharge test. If this is not known the test should be conducted under full load so this can be determined. In addition it should be known how long it will take surfaces to go below the ignition temperature of the fluid. If this information is not available surface temperatures should be measured by thermocouples located on turbine, combustor, compressor and exhaust systems. The autoignition temperature of lubricating oil may be assumed to be 700°F (371°C), for fuel oil the autoignition temperature is 500°F (260°C). The minimum duration of 10 minutes was selected because some aeroderivative turbines had rundown times of 5 min It was decided that a 10 min minimum would provide an adequate factor of safety for these units.

C.3 Lubrication Oil and Hydraulic Oil Systems for Gas Turbines

Lubricating oil, hydraulic oil and fuel oil are most commonly involved in fire scenarios involving gas turbines. The oil system is needed for lubrication, hydraulic (power) and lift oil systems. The hydraulic oil system operates valves that control gas flow. The lift oil system allows the turbine to rotate at low speeds on startup and shutdown. The fluid typically used in lubricating oil systems is mineral oil. The fluid used in hydraulic oil systems is mineral oil where the system shares the same tank as the lubricating oil system. If there is a separate tank the fluid may be mineral oil or a less flammable hydraulic fluid. Table 4 gives information on lube oil and hydraulic oil systems for three major turbine manufacturers. The fluid quantities are for 60 Hz machines. The lube oil quantities would be greater for 50 Hz machines.

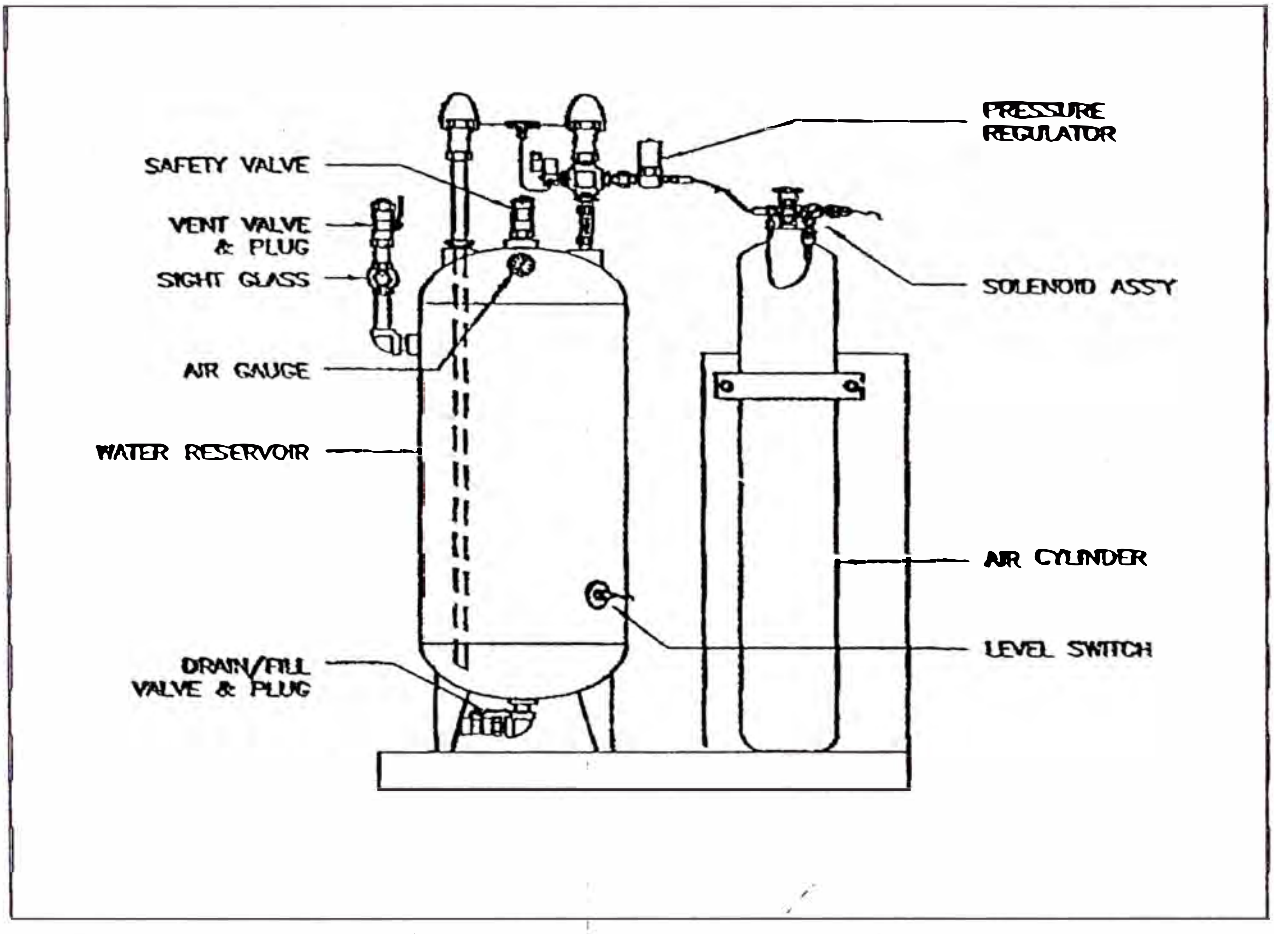

Fig. 11. Arrangement of water reservoir and air cylinder for water mist system. (Securiplex)

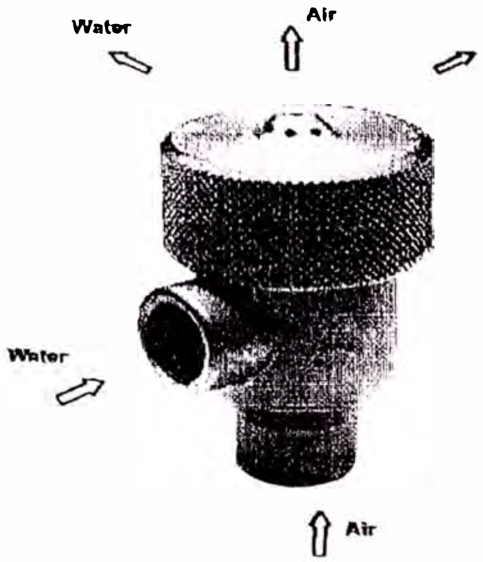

Fig. 12. Nozzle for water mist system.

Table 4. Lubrication and Hydraulic Oil Systems for 60 Hz Gas Turbines

			Lube Oil System			Hydraulic Oil system		
Mfr.	*Model*	*Rating MWe*	*Tank (gal)*	*Flow (gpm)*	*Pressure (psi)*	*Tank (gal)*	*Flow (gpm)*	*Pressure (psi)*
ABB	GT 8C	53	Main-5,000 Aux-1,700	840	100	265	55	360
	GT 8C2	57	same			same		
	GT 11N2	115	4,000	450	94	same		
	GT 24	183	5,860	665	87	none	55	580
GE	Frame E Model 6B	40	3,000	500	tank-100 psi bearings-25 psi	none	10-30	1500
	Frame E Model 6E	80	3,500 (1)	500	same	150 (2)	same	
	Frame E Model 9E	115	3,500 (1)	500	same	250-300 (2)	same	
	Frame F Model 6F	70	6,500 (1)	700-750	same	50 (2)	same	
	Frame F Model 7F	175	6,500 (1)	same		150 (2)	same	
	Frame F Model 9F	240	6,500 (1)	same		250-300	same	
Siemens	Model 64	60	3,350	325	tank-77 psi bearings-20 psi	100	20	300
	Model 84.2	100	3,500	400	same	200	same	2400
	Model 84.3	170	3,750	same	same	80	same	2500

(1) Generating set is available with both gas turbine and steam turbine. The lube oil quantity given is for the gas turbine only. If steam turbine is provided lube oil quantities would be 50% greater than shown.

(2) If there is gas turbine only mineral oil is used as the hydraulic fluid. The supply is from the lube oil tank. If combined cycle a separate hydraulic system is used with Fryquel EHC, an Approved hydraulic fluid.

C.4 Reignition in Gas Turbines after Flameout

If a flameout occurs in a gas turbine, the flow of fuel must be shut off quickly. If fuel continues to flow for a period greater than the autoignition delay time of the particular fuel in use, it will reignite in an uncontrolled manner.

The cutoff of fuel involves three steps: 1) sensing flameout, 2) detecting flameout signal by the control system, and transmitting signal to the fuel shutoff valve, 3) closing fuel shutoff valve.

Flameout is sensed by flame detectors mounted on the combustor casing, aimed through an opening in the combustor liner at the flame. Figure 13 shows an ultraviolet flame detector suitable for this application. This detector can sense the absence of flame in 200 ms. Two such devices are usually installed, located at the top two combustor cans, or at the top of single-can or an annular combustor. The sensors are driven through an amplifier by d.c. voltage. When the sensor is excited by a source of ultraviolet radiation it transmits pulses of current at a frequency corresponding to the intensity of the radiation source. These pulses are integrated in the amplifier, that provides an output signal of zero voltage for flame, and plus voltage for no flame.

Fig. 13. Flame detector and amplifier. (Honeywell)

Each of the two flame detectors produces a signal at one of the two output terminals of the amplifier. These signals are transmitted to a programmable controller that scans the inputs and makes an appropriate decision. If both inputs provide a zero signal (indicating that both detectors are showing flame) no action is taken. But if only one input is plus, an alarm is actuated; if both inputs are plus (indicating flameout at both detectors), the fuel valve instantaneously closes. This voting arrangement avoids spurious trips that could occur if one sensor is affected by something extraneous, if its quartz lens is clouded by smoke, or if it becomes inoperative. The input logic is typically scanned eight times a second. This means that it could take 125 ms to detect a flameout.

The third phase of fuel cutoff closes the fuel stop valve. This valve may be up to 4 in. (10 cm) diameter for liquid fuels and up to 8 in. (20 cm) for gaseous fuels. In older gas turbines this is a two-position oil-relay type valve is normally closed (NC) and is opened on start up and held opened during operation by hydraulic pressure. When emergency shutdown is required, a relay-operated solenoid valve dumps the hydraulic fluid to drain, and the stop valve closes under spring load. A 3 in. (7.5 cm) valve closes in 300 ms. The time from flameout to fuel cutoff is estimated to be 675 ms.

In current installations, the fuel stop-valve is usually a solenoid valve. It should be normally closed, that is, it opens when the solenoid is energized, and closes under spring load when de-energized.

It is possible to design a 3 in. (7.5 cm) semi-direct lift internal-pilot valve to close in 100 ms with liquid fuel. It is estimated that an 8 in. (20 cm) internal pilot valve should close in 200 to 250 ms with gaseous fuel.

It is, therefore, possible to detect flameout, evaluate the decision logic, and cut off the fuel flow to the combustor in less than 750 ms, even in the largest gas turbines. In smaller machines, it may be possible to achieve this in 500 ms.

C.5 Less-Flammable Lubricants And Hydraulic Fluids

Fire-resistant lubricants have been used in gas turbines for over twenty years. They have not been widely used due to: a) cost of the lubricants, b) cost of conversion of lubrication and hydraulic systems to use less-flammable fluids, c) toxicity which requires special handling, d) emulsification with water, requiring special treatment, and e) ecotoxicity, requiring special recovery methods.

Synthetic fluids have been developed to overcome toxicity and emulsification concerns. The cost of less flammable lubricants are considerably more than mineral oil. However, if the manufacturer's recommendations are followed, the fluid should last the lifetime of the turbine. Caution should be used when considering a change to less flammable fluids in an existing turbine. The turbine manufacturer should be consulted to ensure the fluid is compatible with piping, paint, gaskets, and "o" rings in the system. If the inside of the lube oil tank is painted this may prevent retro filling with less flammable fluids. Less flammable fluids have higher flash points and autoignition temperatures than mineral-based fluids. Sprays of these fluids can ignite on contact with a hot surface but they do not continue to burn after flowing away from the hot surface. Less flammable lubricants are listed under the less flammable hydraulic fluid section in the *Approval Guide*. Two fluids which have been used as lubricants for gas turbines are: Reolube Turbo fluid 32BGT made by FMC Corporation and Fyrguel GT made by AKZO Nobel Chemicals. Both fluids are listed as Group II less flammable hydraulic fluids.

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