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BP Process Safety Series

LNG Fire Protection and Emergency Response

A collection of booklets describing hazards and how to manage them

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This booklet is intended as a safety supplement to operator training courses, operating manuals, and operating procedures. It is provided to help the reader better understand the 'why' of safe operating practices and procedures in our plants. Important engineering design features are included. However, technical advances and other changes made after its publication, while generally not affecting principles, could affect some suggestions made herein. The reader is encouraged to examine such advances and changes when selecting and implementing practices and procedures at his/her facility.

While the information in this booklet is intended to increase the store-house of knowledge in safe operations, it is important for the reader to recognize that this material is generic in nature, that it is not unit specific, and accordingly, that its contents may not be subject to literal application. Instead, as noted above, it is supplemental information for use in already established training programmes; and it should not be treated as a substitute for otherwise applicable operator training courses, operating manuals or operating procedures. The advice in this booklet is a matter of opinion only and should not be construed as a representation or statement of any kind as to the effect of following such advice and no responsibility for the use of it can be assumed by BP.

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Introduction to LNG

The purpose of this booklet is to provide an overall understanding of Liquefied Natural Gas (LNG), the potential emergency situations that may arise at facilities and how to deal with these incidents as well as general LNG safety issues.

1.1 Brief history of LNG

Natural gas liquefaction dates back to the 19th Century when British chemist and physicist Michael Faraday experimented with liquefying different types of gases, including natural gas. German engineer Karl Von Linde built the first practical compressor refrigeration machine in Munich in 1873. The first LNG plant was built in West Virginia in 1912 and it began operation in 1917.

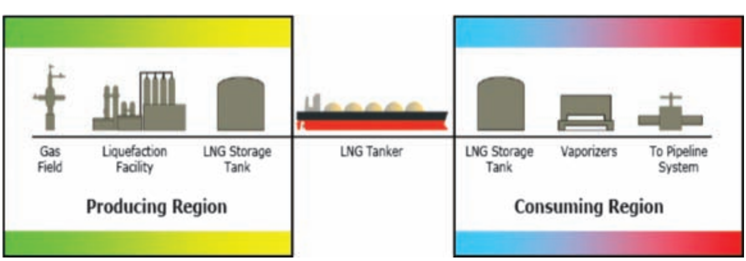
The first commercial liquefaction plant was built in Cleveland, Ohio, in 1941. The LNG was stored in tanks at atmospheric pressure. The liquefaction of natural gas raised the possibility of its transportation to distant destinations.

In January 1959, the world's first LNG tanker, *The Methane Pioneers*—a converted World War II liberty freighter containing five, 7000 bbl aluminium prismatic tanks with balsa wood supports and insulation of plywood and urethane—carried an LNG–cargo from Lake Charles, Louisiana, USA to Canvey Island, United Kingdom.

This demonstrated that large quantities of liquefied natural gas could be transported safely across the ocean.

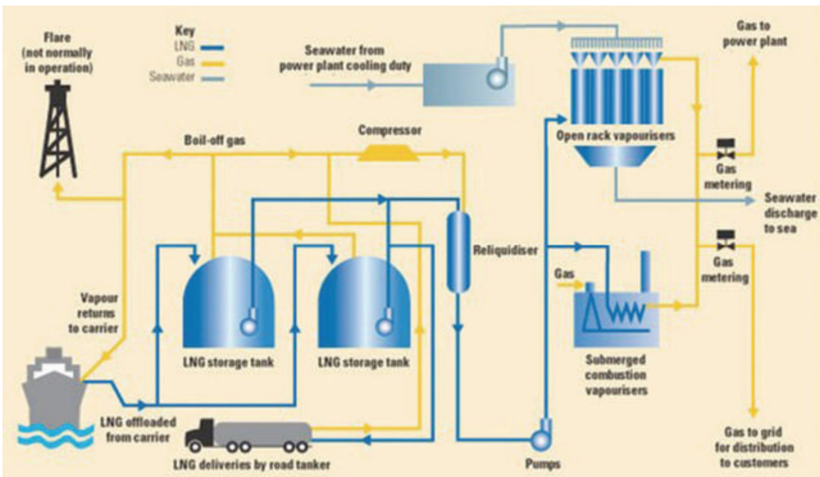
1.2 Basic LNG production and customer flow

Since the early days, LNG production, export, import and distribution has followed a similar pattern as shown below:



1.3 LNG import terminal facilities

The diagram below illustrates typical flow of an import terminal.



2

LNG properties

2.1 LNG composition

LNG is natural gas in liquid form. The natural gas from which LNG is condensed is a mixture of light hydrocarbons of methane (CH_4), ethane (C_2H_6), propane (C_3H_8), and sometimes butane (C_4H_{10}) and trace amounts of five-carbon (pentane) and higher species. Nitrogen, carbon dioxide (CO_2), water, and trace amounts of helium, hydrogen sulphide and mercury may also be present. LNG is predominantly methane, usually, though not always, over 85% by volume.

Liquefaction describes the process of cooling natural gas until it forms as a liquid.

Composition of LNG varies depending upon the natural gas source. Gas produced from gas wells (non-associated gas) and from liquid hydrocarbon wells (associated gas) varies widely in composition. The gas is processed to provide consistent composition and combustion characteristics. This consistency is termed pipeline-quality gas.

Pipeline-quality natural gas typically contains 85 to 99% methane and also contains the heavier hydrocarbons as shown above.

Natural gas is cooled and condenses to form LNG at approximately −162°C (−260°F). It is clear and colourless like water, but weighs about half as much as the same volume of water. One volume of LNG equals approximately 618 volumes of natural gas at standard temperature (16°C/60°F) and atmospheric pressure (14.7 psia/1 bar).

It is this ratio of liquid to gas that makes LNG economically attractive.

2.2 Cryogenics

LNG is a cryogenic liquid with temperatures in the order of −162°C (−260°F), at atmospheric pressure. LNG boils at −162°C (−260°F) and therefore will vaporize rapidly if released accidentally.

Other common cryogenic liquids include liquid oxygen, nitrogen, helium, argon and hydrogen. The table below shows the boiling points of some common liquids in both Celsius (°C) and Fahrenheit (°F).

Celsius	Farenheit	
100	212	Water boils
21	70	Room temp
0	32	Water freezes
−0.5	31	Butane boils
−33	−27	Ammonia boils
−42	−44	Propane boils
−162	−260	LNG boils
−183	−298	Oxygen boils
−195	−319	Nitrogen boils
−252	−422	Hydrogen boils
−270	−454	Helium boils
−273	−460	Absolute zero

2.3 Embrittlement

Safe use of LNG or any cryogenic substance requires an understanding of how materials may change their behaviour at cryogenic temperatures. For instance, at cryogenic temperatures, carbon steel loses its ductility and becomes brittle. As a result, aluminium and stainless steel are typically used in the liquefaction and regasification sections of LNG terminals.

2.4 Heat of vaporization and ‘cold burns’

Latent heat of vaporization is the amount of heat required by a substance to change from a liquid to a gas. The heat absorption (cooling) effect of water evaporating off the skin is an example of this. In liquids, molecules have much greater attractive forces holding them together than in gases. To form a gas, the attractive forces of the liquid are overcome by absorbing heat. This absorbed heat, or the heat of vaporization, is 551 kJ/kg (220 Btu/lb) for methane.

The heat of vaporization contributes to personal injury ‘cold burns’ because, in addition to the low temperature of the liquid, the vaporizing LNG absorbs heat from the surrounding skin.

2.5 Density and specific gravity

The specific gravity of a liquid is the ratio of density of that liquid to density of water (at 16°C/60°F). The specific gravity of a gas is the ratio of the density of that gas to the density of air (at 16°C/60°F). A gas with a specific gravity of less than 1.0 is lighter than air (buoyant) and will easily disperse in open or well-ventilated areas. A gas with a specific gravity of greater than 1.0 is heavier than air (negatively buoyant). Thus, it will tend to stay near the ground and not disperse easily into the air.

The density of methane as a vapour at atmospheric pressure and standard temperature (60°F or 16°C) is 0.424 lb/ft^3 (6.8 kg/m^3). The specific gravity of methane under the same conditions is about 0.45.

Although the heavier hydrocarbons have densities and specific gravities greater than methane or air, these hydrocarbons are evenly dispersed in natural gas, just as nitrogen and oxygen are evenly dispersed in air. Vapours from gasoline and diesel fuel have specific gravities greater than air and therefore do not dissipate as rapidly as natural gas.

The density of gases including methane (and natural gas) increases as temperature decreases. This behaviour affects the dispersion of a cold methane vapour cloud. At temperatures below −107°C (−160°F), the density of methane is greater than that of air at an ambient temperature of 60°F.

Thus, LNG vapour below −107°C is negatively buoyant and more likely to accumulate in low areas until it warms. Above −107°C, LNG vapour is positively buoyant and disperses more easily.

It is obvious that heat input to LNG in any form will therefore enhance dispersion. Such heat may be transferred from passive sources such as atmospheric humidity (which is a significant source), the ground or impoundment pits and structures.

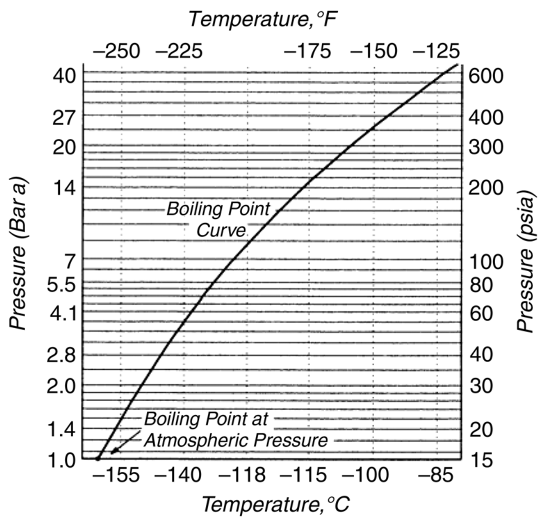
2.6 Boiling point and vapour pressure

At atmospheric pressure (14.7 psia or 1 bar), methane boils at −162°C (−259°F). An increase in the pressure of stored liquid raises the boiling point. Thus, for all liquids there is a correlation between pressure and the boiling temperature.

In equilibrium (when vapour and liquid are at the same temperature) there is a unique temperature and pressure combination, which can be represented by a vapour pressure curve as illustrated below. In pressurized LNG storage vessels (at approximately 35 psig or around 2 barg), methane boils at about −149°C (−237°F).

The graph below shows the pressure/temperature curve for methane.

Heavier hydrocarbons have higher boiling points (less volatile) than methane. Thus, the vapour in the vapour space above the LNG in a storage tank or vessel will include relatively higher concentrations of the lighter LNG components (methane and nitrogen), while the liquid portion will have relatively higher concentrations of the heavier hydrocarbons.



2.7 Changing composition/weathering

As LNG evaporates, its composition changes because the lighter components vaporize faster than the heavier components. These composition changes are relatively minor and have no safety implications.

LNG can potentially change in composition in each step of processing and handling. This change, known as 'weathering', is almost always in the direction of lowering methane content, which increases the relative ethane and propane content.

This weathering can and will occur wherever there is both LNG liquid and vapour, both of which have a different composition (and can be determined by equilibrium calculation). Methane is more volatile because it has a lower boiling point (162°C or −259°F) than ethane (88°C or −127°F) and propane (−42°C or −44°F). Thus, the vapour will be preferentially methane rich, whereas the heavier components will stay in the liquid phase.

As increasing amounts of methane vapour are taken from the storage system, the methane will be depleted from the liquid. Therefore, if only the vapour phase in a tank is used, the last residual liquid phase will be mostly ethane and propane.

It should be noted that weathering may also occur in LNG held in LNG road tankers for transport and significant delays in delivery of the tanker load from the day of loading will effect composition. This may be significant where the LNG is to be used as road vehicle fuel, which needs typically 99% methane content.

A comparison of hazards of various fuels is provided in the table below.

Hazard	**LNG**	**LPG**	**Gasoline**
Toxic	No	No	Yes
Carcinogenic	No	No	Yes
Flammable	Yes	Yes	Yes
Form vapour clouds	Under special conditions	Yes	Yes
Asphyxiant	Yes, in confined spaces	Yes, same as LNG	No
Other health hazards	No	No	Eye irritant, narcosis, nausea, others
Flash point °F (°C)	−306 (−188)	−156 (−104)	−50 (−45)
Boiling point °F (°C)	−258 (−161)	−44 (−42)	90 (32)
Explosive limits in air (%)	5–15	2.1–9.5	1.3–6
Stored pressure	Ambient	Pressurized	Ambient
Behaviour if spilled	Evaporates, forming visible 'cloud' that disperses readily	Evaporates forming vapour cloud slow to disperse	Form a flammable pool, environmental cleanup required

2.8 LNG flammability limits

The lower and upper flammability limits of methane are approximately 5% and 15% by volume respectively.

Methane leaking from a tank in a well-ventilated area is likely to mix rapidly and dissipate to less than 5%. Because of the rapid mixing, only a small area near the leak would have the proper concentration for the fuel to ignite.

The flammability limits of natural gas are also affected by the gas composition. Heavier hydrocarbons have lower flammability limits than methane, causing the lower flammability limit of LNG to decrease with increasing concentrations of heavier hydrocarbons. In an LNG accident scenario, the maximum hazardous area will typically be defined by methane properties.

2.9 Auto ignition temperature and ignition energy

Auto Ignition Temperature (AIT) is the lowest temperature at which a gas will ignite after an extended time of exposure (i.e. several minutes).

This temperature depends on factors such as air-fuel mixture and pressure. In an air-fuel mixture of about 10% methane in air, the auto ignition temperature is above 540°C (1000°F).

Temperatures higher than the auto ignition temperature will cause ignition after a shorter exposure time to the high temperature.

The ignition temperature of LNG varies with composition. If the concentration of heavier hydrocarbons in LNG increases, the auto ignition temperature decreases.

In addition to ignition from exposure to heat, the vapours from LNG can be ignited immediately from the energy in a spark or open flame. The minimum spark ignition energy required to ignite the most easily ignited mixture of methane in air is 0.29 mJ (millijoule). Practically speaking, most sparks have enough energy to ignite a flammable mixture of methane in air.

3 LNG hazards

3.1 Vapour clouds and vapour dispersion

A major potential hazard of LNG activity is the formation of a vapour cloud from an accidental release of LNG.

Whilst a vapour cloud would not be toxic and is only an asphyxiant at concentrations above 50% methane, obviously it becomes flammable when adequately mixed with air. An LNG vapour cloud, like any gaseous cloud influenced by the wind, can be carried away from its source. The wind serves both to carry it and to disperse it and the higher the wind speed the more the vapour will disperse and 'dilute'.

Dispersion is also influenced by factors such as atmospheric stability, humidity, terrain, and ground to air temperature difference. At a great enough distance from the source, the cloud will be dispersed enough so that it is no longer flammable because the gas concentration is below the LFL (Lower Flammability Limit).

The LFL is 5% by volume. LNG vapours are initially cold and heavier than ambient temperature air so mixing and dispersion are reduced. When the vapour reaches a temperature of 107°C (−160°F), the specific gravity is 1.0 compared with ambient temperature air. At temperatures higher than −160°F, the specific gravity is less than 1.0 and the vapours are buoyant, which enhances dispersion rates.

3.2 Vapour cloud visibility

A unique characteristic of an LNG vapour cloud emanating from a liquid spill or pool is that it is generally visible. Because of the low temperature of the LNG vapour, a vapour/air mixture temperature will typically be less than the moisture dew point of the air. This results in atmospheric condensation on the outer edges of such a cloud that appears as fog. This is a clear indication there has been a cold LNG vapour release, and a good indication of the direction of the dispersion.

The visible area, which appears similar to steam/fog, as shown in the photograph, is an indication of the gas hazardous area but it must be remembered that the vapour exists outside of the visible cloud and therefore the hazard extends beyond the visible cloud area.

Typical LNG vapour cloud formation. The condensation of the surrounding moisture indicates gas presence but it must be noted that the flammable hazard extends beyond the visible cloud.

In the USA, CFR Title 49, Part 193-Liquefied Natural Gas Facilities: Federal Standards, Section 193.2059 specifies each LNG container and LNG transfer system must have a dispersion exclusion zone around it that is owned by the facility operator. A minimum dispersion distance must be computed for the impounding system in accordance with the applicable dispersion parametres. It must also use the DEGADIS (Dense Gas Dispersion) Model developed by the University of Arkansas and funded by GRI, EPA, USCG and several others. Alternatively, a model meeting the requirements of paragraphs (ii) through (iv) in the CFR Section 193.2057(c) may be used.

The exclusion zone must be large enough to encompass the part of the vapour cloud that could be flammable. In order to account for irregular mixing of the vapour cloud, the regulations designate the vapour cloud hazard area as the area where the average gas concentration in air is equal to or greater than 2.5% (one half of the lower flammability limit of methane). This provides a significant margin of error to account for irregular mixing.

3.3 Effects of heavy rainfall on LNG

During the October 2006 fire school, the small pit was loaded with about 30 cm (6") LNG, ready for testing work. A heavy rain storm moved over the fireground just after loading, driven by winds of up to 48 kph (30 mph). The heavy rainfall caused rapid vaporization as it warmed up the liquid in the pit and the winds blew vapours at relatively lower levels than normal. The vapours were visible from a distance of >75 m (246 ft). Due to the heavy rainfall and winds, there was no possibility of using high-expansion foam to try to reduce vaporization. All LNG in the pit was vaporized after only 25 minutes, whereas under ambient open air conditions, the LNG would remain for some hours.

Obviously, for areas where heavy rainfall, thunderstorms and high winds may frequently occur, design of pits, foam application and the response to possible LNG releases may need to be reviewed and responder emergency response plans will need to reflect the potential for greater vapour migration than 'normal' and the hazards that this may create.

NFPA 59A also deals with the vapour cloud dispersion zone in similar terms.

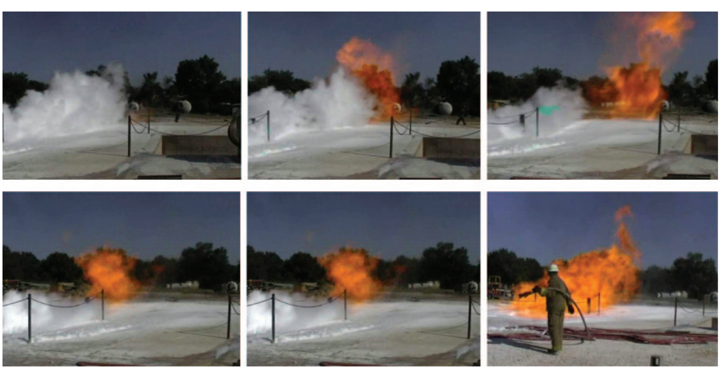
ACCIDENT This was not an LNG related incident, but it involved two operators driving to investigate a vapour cloud in a tank farm. Both were killed when the vehicle ignited the vapour and destroyed the vehicle, as this picture clearly shows. Care is always needed when investigating gas or vapour release incidents or gas alarms. *Picture courtesy Resource Protection International*.

3.4 Flash fires

If LNG vapours are ignited at a distance from the liquid spill or the release source, and there is no confinement of the vapours, the vapours will burn back to the liquid source in what is termed a 'flash fire'.

Typically, the burn back, or flash fire, will occur over several seconds as a maximum. The flash fire duration is dependent on the distance of the vapours from the liquid and the stoichiometry (air/fuel mixture) of the vapour cloud. Although typically several seconds pass before the flame returns to sources, it is quite possible for the 'flash' to occur within one second or less.

The photographs below are in clockwise sequence from top left over an interval of about five seconds.



(Photographs courtesy Resource Protection International.)

3.5 Radiant heat hazards

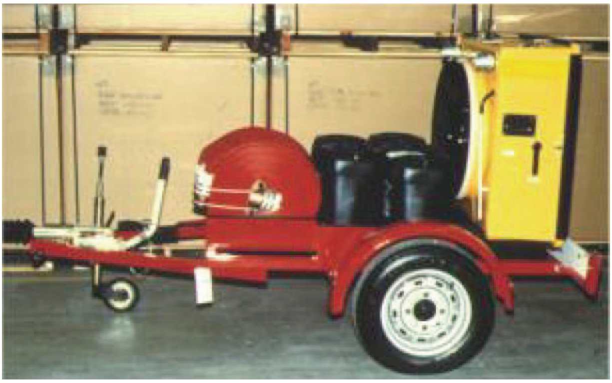
LNG facility operators, fire responders, design and project engineers all need to be aware that burning LNG produces very high levels of radiant heat compared to other flammable liquids such as gasoline.

For burning methane, typical heat emissivity is in the range of 220 kW/m^2 (12000 BTU/min/ft^2), compared to 140 kW/m^2 (7600 BTU/min/ft^2) for gasoline. This means an LNG pool fire will emit around 57% more radiant heat than an equivalent sized gasoline pool fire.

Deployment of mobile or portable equipment, especially foam producing equipment which has to be moved close to catchment pits or spill retention areas, is a very hazardous strategy due to these high radiant heat levels—hence the need for fixed foam systems, remotely operable at a safe location.

In practical language, the high methane content of LNG results in a clean burning fire, but this also means there is little, if any, smoke produced to act as a mask for heat output, as shown in the photo above. The high levels of radiant heat are intense and greatly exceed that of other flammable liquids. The heat levels should never be underestimated by responders, for any considered mobile or manual intervention.

The 2006 BP fireground LNG exercises in Texas have shown that whilst properly specified and approved turnout bunker gear (PPE) for responders can withstand some of this radiant heat for a very short time—*at a distance*—the reflective tapes and strips and even insignia and badges on turnout gear will soon melt if they are too close to the pool fire.



For emergency response, the radiant heat levels produced from an LNG fire greatly exceed that of a typical flammable liquid fire such as gasoline or diesel or crude oil. The portable high expansion foam unit shown in this photo should therefore not be considered for terminals, due to the risks to responders in deployment. *Photo courtesy Resource Protection International*.

3.6 Explosion hazards

In simplest terms, LNG and natural gas cannot and do not explode unless they are confined or if they are in a heavily congested plant area.

A requirement for methane/LNG explosions is either total confinement (as in a closed room) or partial confinement (as in a very congested, dense field of obstructions such as found in a process area of a liquefaction facility).

The inability of *unconfined* methane clouds to explode is due to the low laminar flame speed at which a flame will move through a mixture of methane and air. Flame speeds are too slow to produce the pressure front needed for a significant overpressure in unconfined areas.

However, in partial confinement, a flame front can accelerate, generating turbulence, and from this turbulence a dangerous pressure front and overpressure can result. The density and extent of obstructions, therefore, can directly affect the severity of an explosion. Furthermore, cold or heavier-than-air non-LNG vapour, such as flammable refrigerants as found in liquefaction facilities, can flow into confined spaces including drains and sewers where they may result in an explosion if ignited.

An explosion is generally defined as the sudden release or creation of pressure and generation of high temperature as a result of a rapid change in chemical state (usually burning) or a mechanical failure. Such an event creates an overpressure, which can cause injury and damage. Thus, the severity of an explosion can be gauged by overpressure, and more specifically, the overpressure as a function of distance. This ranges from a fire with no overpressure to a detonation producing a shock wave.

(Note: In this discussion, 'explosion' refers to the formal term 'deflagration', not 'detonation'. A deflagration is an exothermic reaction which propagates from

the burning gases to the unreacted material by conduction, convection and radiation. A detonation is an exothermic reaction characterized by the presence of a shock wave in the material that establishes and maintains the reaction.)

3.7 Boiling liquid expanding vapour explosion

A Boiling Liquid Expanding Vapour Explosion (BLEVE) typically occurs with pressurized LPG storage facilities, typically spheres, horizontal vessels (bullets) and LPG bottles.

Whilst previous LNG industry experience has clearly indicated that BLEVE had not and would not occur in onshore LNG storage tanks, an LNG road tanker incident occurred in Spain in 2005, involving a rollover/crash and fire with a subsequent BLEVE style fireball explosion. It should be recognized this was an isolated, road tanker incident and was initiated by the road tanker overturning after the driver lost control and therefore the event is peculiar to the road transport of LNG and not onshore LNG storage.

This road tanker incident is covered in detail in the appendix. The differences in tank construction between a road tanker and fixed storage tank are clear and the road accident scenario does not apply. The road tanker inner tank failure would also not apply.

The BLEVE phenomenon occurs typically with pressurized Liquid Petroleum Gas (LPG) when a pressure vessel containing a flammable liquefied gas is heated by a fire to a temperature high enough to weaken the steel of the vessel.

Essentially, the fire evaporates the LPG in the tank, which raises the pressure in the tank. The relief valves vent the high pressure vapour to limit the pressure in the tank. The evaporating liquid provides cooling of the tank metal below the liquid level.

The vapour above the liquid provides much less cooling and increases in temperature. As the liquid level in the tank drops, the flames from the fire impinge on a larger and larger part of the tank.

Without the cooling effect of the liquid in the tank, the yield strength of the metal at the top of the tank is reduced as the metal temperature increases.

(Tank design will have a significant safety factor relative to yield stress at ambient temperature. However with direct flame impingement, high metal temperatures will result in the actual yield stress being lower than the relief valve set pressure.)

Once the yield stress is exceeded, the metal in the tank fails catastrophically and the remaining LPG is released. Once the LPG is released to atmospheric pressure, a large fraction of the liquid remaining will flash violently into a rapidly expanding vapour cloud.

This catastrophic event typically though not exclusively occurs at the high relief valve pressure, spewing metal and burning hydrocarbon into the surroundings. Debris from an exploded LPG tank BLEVE can travel great distances due to the high pressure in the tank. The flame propagation speed of the LPG will create a significant overpressure from the burning vapour cloud.

The BLEVE shown can occur with LPG vessels and containers, sometimes spectacularly as is the case in this sequence of photographs taken a few seconds apart, but LNG storage tanks do not have the pressurized storage aspect of LPG and therefore do not have the BLEVE risk. *Photograph courtesy Resource Protection*.

LNG is normally stored at low pressure in well-insulated or vacuum-jacketed tanks. In both cases, the containment is double-walled with insulation between the walls. Full containment tanks have concrete outer walls. LNG is also stored at low or cryogenic temperatures.

During a fire, the outer shell will prevent flame impingement and the insulation keeps the fire from vaporizing the LNG as rapidly as an uninsulated tank will allow.

Even if the vacuum jacket loses its vacuum, the insulation at atmospheric pressure and the vapour space are still good insulation. With the double wall and insulation, there is no direct flame impingement on the inner tank. Without direct flame impingement, the cold LNG vapours will keep the inner tank from increasing in temperature to a point where the yield stress is exceeded.

LPG also has other properties that make this situation worse. The laminar flame speed for LPG is significantly higher than methane, leading to overpressure. This exacerbates the situation and can lead to detonation of vapour cloud explosions. With the tank at low pressure, the effect of a failure (even if one did occur) would result in a fire rather than an explosion.

A BLEVE type accident, though experienced by LPG vessels, is not a credible accident for LNG fixed storage tanks because the outer tank material, design and insulation protects the inner vessel and gives time for a cooling action to take place.

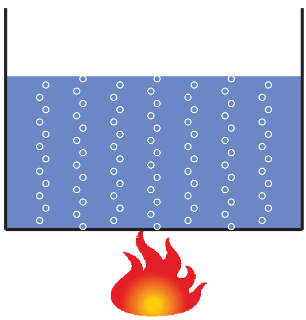
3.8 Rapid phase transformation (RPT)

As is well known, boiling is caused by heating a liquid to its boiling temperature. Less appreciated is that a liquid can be inhibited from boiling (superheating) if there is not an energy concentration point, referred to as a nucleation site.

The common household visualization of this phenomenon is the stream of bubbles from precise points of origin at the bottom of a pan of water just reaching its boiling point. These are minute surface irregularities that start the formation of each bubble.

When a liquid droplet is exposed to a hot surface, the evaporation rate is high enough that the liquid droplet is supported by a film of the evolving vapour and does not actually touch the hot surface. The common experience of this phenomenon is a water droplet on a hot, greased pan, which seems to dance on the surface without touching it. The technical term for this occurrence is called the Liedenfrost effect. In this case, the water droplet can become superheated because there are no nucleation sites provided by the supporting gas film.

Theoretical Foundation for the RPT Phenomena



This is demonstrated by the stream of bubbles originating from precise points at the bottom of a pan of water as it reaches its boiling point.

These precise points are minute surface irregularities in the pan that start the formation of each bubble.

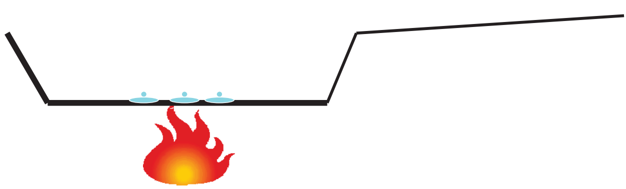
They are energy concentration points or ‘nucleation sites’.

Theoretical Foundation for the RPT Phenomena

This is demonstrated by water droplets on a hot greased pan as they dance across the surface without touching it.

This is called the Liedenfrost effect.

The droplets become superheated because the supporting gas film does not provide a nucleation site.



In a similar manner, an LNG spill on water has a combination of sufficient temperature difference and surface tension to produce large droplets, or puddles, of LNG supported above the water by the film of evaporation vapour.

When LNG is spilled on land or water, the LNG is initially very cold (−162°C/−260°F). The land or water surface is, by comparison, very hot. For typical export facilities over water, ocean temperature can be in the order of 15°C (60°F). This high temperature difference of over 175°C (320°F) causes LNG boiling and because the difference in temperature is so high initially, a vapour film is formed at the contact point between the LNG and the underlying spill surface.

This vapour film will persist until the spill surface cools enough or until the LNG temperature gets warm enough. So long as the vapour film exists, heat transfer is greatly reduced since the vapour layer acts as an insulator. When the difference in temperature between the LNG and the spill surface gets smaller, the vapour film is destroyed and a different and more rapid heat transfer mode commences.

The rate of heat exchange between the cold LNG and the warmer spill surface is now tremendously larger than it was with the vapour film in place—and as a result the LNG is heated almost instantaneously whereupon a Rapid Phase Transition occurs. Once this Rapid Phase Transformation (RPT) is initiated, it proceeds through the superheated LNG almost instantly thus involving potentially large amounts of LNG.

If the LNG is nearly pure methane, this turbulent but not violent mode of evaporation will continue to completion. In instances where the LNG contains ethane and propane, the methane will evaporate first and enrich the composition of the remaining LNG liquid.

The overpressures are not comparable to chemical explosions, but the size and energy can cause damage due to the momentum of displaced water. RPT’s range in size from small ‘pops’ to events large enough to damage lightweight structures and be a potential hazard to personnel.

An RPT occurring during a full scale test at Montoire, France. A low methane content LNG was used during the tests. The LNG is flowing on to the sea from an overhead line. The crown of the ‘flameless explosion’ effect can be seen in comparison to the low level LNG vaporizing on the water. Some RPTs have caused structural damage. Responders must be aware of the overpressure potential if a RPT occurs. *Photograph courtesy Gaz de France*

The following should be noted in relation to RPTs.

- RPTs are more likely to occur in LNG mixtures containing high proportions of ethane and propane;
- High methane content LNG is unlikely to undergo an RPT;
- Higher cold liquid spill rates and prolonged high rate spill durations are more likely to produce RPTs;
- Only a small fraction of spilled LNG was observed to undergo RPT.

It is also of note that in one large scale RPT field trial, an RPT occurred followed by ignition of the vapours. The cause of the ignition is not known nor have attempts been made to try to recreate this incident. The ignition by RPT is therefore not a proven fact.

During the BP LNG Workshop at the Texas A&M fire school, repeated attempts were made to create a RPT using water hose streams. The LNG used for these attempts was initially 98% methane and then for latter tests was in the order of 96%.

Despite repeated attempts at no time did a RPT occur, thus indicating that high methane content LNG is not likely to create a RPT. The evidence is that lower methane content LNG is liable to undergo a RPT, although the methane content 'limit' is not quantified.

Photo courtesy Resource Protection International

Water stream forcibly introduced into LNG in a retention pit. No RPT occurred despite this operation being repeated many times. The high methane content (99%) LNG used in this particular instance, is not likely to create a RPT. 96% methane content LNG was also used in RPT attempts but also failed to develop a RPT. However, it must be noted that RPT attempts with lower methane content LNG should not have personnel and handlines in close proximity, due to potential overpressures.

It is important for those dealing with LNG, especially at facilities over water, to recognize the RPT hazards from overpressure.

Several examples of accidental RPT events are listed below for information.

Canvey, UK, 1973
During normal LNG carrier off-loading operations a 100 mm (4 inches) bursting disc on a 350 mm (14 inches) discharge line failed. LNG was released into one of the LNG tank bunds where water had collected from recent rainfall.

Three explosions were heard, but the only damage was a broken window in an adjacent building.

Arzew, Algeria, 1977
Due to the rupture of an aluminium valve, several thousand m^3 of LNG were released over a ten hour period.

The leakage took place on the ground, near a frozen soil tank, but spread onto the sea and several RPTs were observed. Overpressures and/or projectiles from the overpressures damaged a number of windows in the general area.

Badak, Indonesia, 1992
An LNG leak occurred when starting a liquefaction train. A decision was made to continue train operations despite the leak and water curtains were actuated to reduce vapour cloud size and migration.

Approximately eleven hours after the plant had been started up, RPTs occurred in a concreted slab covered drainage channel. Resultant overpressures broke the channel and concrete slabs as well as damaging adjacent pipework. Some concrete blocks were thrown up to 100 m (330 ft).

Fos-sur-Mer, France, 1995
During a demonstration of using a vehicle mounted dry powder system monitor to extinguish a 25 m^2 (270 ft^2) LNG pool fire, a RPT occurred because the contents of a water puddle between the vehicle and the LNG pool was blown into the LNG pool by the pressure from the dry powder/nitrogen stream.

A fireball arose from the burning LNG pool fire, doubling the fire size for several seconds. The fire was extinguished as part of the dry powder system demonstration.

Montoire Terminal, France, 1995
A leak occurred on a high pressure stuffing at the top of a waterfall vaporizer unit. Water ran down the outside of the vaporizer tubes into a basin where it was collected to be returned to a river.

The leaking LNG was at approximately 100 barg (1450 pig) when it came into contact with water. An RPT occurred, followed by a few minor 'pops'. The only reported damage was to the corrugated plastic structure surrounding the vaporizer.

3.9 Tests and experiments RPTs

In addition to the above accidental RPTs the following examples are RPT events that occurred during LNG experiments and tests.

Nantes, France, 1971
During an LNG vapour dispersion test, LNG was released onto water of 100 mm (4″) depth. The LNG was released from a 3 m^3 (106 cubic ft) 'tip' tank. Several RPTs were observed after the LNG was released.

Damage occurred to the wooden structure holding the water, the stainless steel tip tank was bent and some ice was ejected outside the water/LNG pool area.

China Lake, USA, 1980
Tests were carried out over a four year period from 1978–1982 to study vapour cloud dispersion. The vapour clouds were produced by releasing LNG on to water.

During tests where high flowrates were used, between 720 to 1080 m^3/h (190,000 to 285,000 US gal/hr), severe RPTs were produced both on immediate contact between the LNG and water, and some time after the spill was introduced to the water.

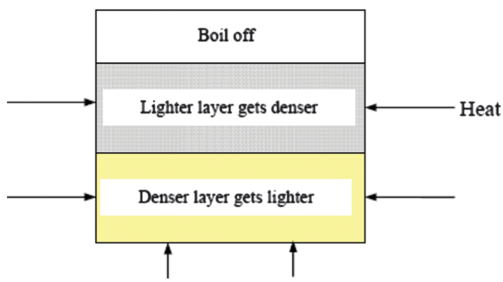
The most severe RPT event created an overpressure estimated to be the TNT equivalent of 3.5 kg (8 lbs).

It will be obvious from the above that RPTs can cause personnel injury as well as damage to plant and equipment and structures. The possibility of overpressures also causing escalation through further releases of LNG or other flammables from vessels, piping or flanges should also be borne in mind.

3.10 Rollover

Rollover can occur in an import facility LNG storage tank if the cargo received is of a different composition from the LNG inventory in the receiving tank and if appropriate tank filling procedures are not used.

When this is the case, temporary density induced stratification may occur, as illustrated below. This in turn will lead to a temperature rise in the lower layer of the LNG, which will cause the stratification to become unstable and result in de-stratification (mixing), commonly known as a 'rollover'.



When this occurs, there will be an increase in the LNG vaporization rate (boiloff) that may cause venting to the atmosphere through the LNG storage tank relief valves.

Operational instrumentation, personnel training and controls are the most effective methods of preventing rollover in a tank. (See also LNG tanks in this booklet for instrumentation.)

3.11 Geysering

The term 'geysering' is used to identify the phenomenon of the expulsion of LNG from a quiescent liquid in piping. The cause is the heating of a saturated (near boiling point) liquid in a lower portion of the piping that quickly boils when the hydrostatic pressure of the liquid farther up in the piping is reduced.

When the liquid at the lower level becomes warm enough to start boiling, bubbles are generated. This reduces the hydrostatic head, which in turn increases the boiling rate. Thus, the geysering becomes self-perpetuating once initiated.

Three familiar and comparative examples are:

- percolating of a coffee pot which has a centre tube;
- the 'Old Faithful' geyser (Yellowstone Park);
- quickly opened soft drink can.

All three of these events have several factors in common as follows:

- the liquid contains a latent gas evolution;
- a reduction in pressure;
- a sudden release of gas.

In an LNG facility, a piping arrangement favourable for geysering is a long, horizontal unloading line ending in a vertical, open-ended pipe into a storage tank. In this case, the static LNG in the horizontal portion of the unloading line increases in temperature until boiling is finally initiated.

The resulting bubbles in the vertical pipe to the top of the tank reduce the liquid density and hence the hydrostatic pressure on the horizontal portion of the line. Once initiated, this reaction goes to completion very quickly. It will very often completely clear the pipe of LNG and increase the tank pressure, causing the relief valves to open.

3.12 Personnel LNG and cryogenic hazards

Asphyxia

Breathing cold vapours is a health hazard. Over a short time it can result in breathing discomfort but prolonged cold vapour breathing can lead to serious illness and should therefore be avoided.

Although LNG vapours are not toxic, they can reduce oxygen content in a room or confined area or enclosure. If anyone inhaled pure LNG vapour, they would rapidly become unconscious and die in a few minutes if not removed from the hazard.

When asphyxia develops slowly through gradual reduction of oxygen content, the victim will have little or no warning and is generally unaware of anything abnormal until it is too late to physically take action.

An oxygen content of 10% is generally considered the lower physical limit of exposure without permanent damage to the human body. This oxygen content corresponds to a methane concentration in the order of 52.4% in normal air.

Consequently, it is recommended that personnel do not enter an LNG cloud for isolation or other purposes, obviously due to the asphyxia hazard but also due to the potential for flash fire.

The following is the internationally accepted stages of gradual asphyxia.

Stage 1 - 21–14% Oxygen by volume
Increased pulse and breathing rate with disturbed muscular coordination.

Stage 2 - 14–10% Oxygen by volume
Faulty judgement, rapid fatigue and insensitivity to pain.

Stage 3 - 10–6% Oxygen by volume
Nausea and vomiting, collapse and permanent brain damage.

Stage 4 - <6% Oxygen by volume
Convulsions, breathing stopped and death.

General cold effects

Prolonged exposure to temperatures below 10°C (50°F) without adequate PPE can result in a decrease of body temperature or cause hypothermia. As the body temperature falls, there is a decrease in the capability to perform both physical and mental tasks. Cardiac disturbance can occur if the body temperature falls below 27°C (81°F).

Cryogenic injuries

The term ‘ice burn’ or ‘cryogenic burn’, although a misnomer, comes from the sensation experienced when liquids or materials at cryogenic temperatures come into contact with the skin. This happens because the nerve endings in the skin cannot easily differentiate between temperature extremes and therefore heat and freezing sensations create similar sensations.

For such cryogenic burns, unlike the effects of heat burns, the freezing and sub-cooling of flesh produces embrittlement of the affected area because of its water content.

Treatment of cryogenic injuries

Treatment of such burns follows that recommended by Dr. William Mills of Anchorage, Alaska and which corresponds to treatment of 3rd and 4th degree frostbite. In these forms of injury the involved area is frozen with ice crystals present in tissues.

- Remove any clothing that may constrict the circulation to the frozen area.
- Immediately place the part of the body exposed to the burn/frostbite in a water bath that has a temperature of not less than 41°C (105°F) but not more than 46°C (115°F). Never use dry heat which will superimpose a burn upon the frozen tissue, as will heat above 46°C (115°F).
- Simultaneously arrange for transportation to a hospital for further therapy and observation. If there has been massive exposure to cryogenic material so that the body temperature is depressed, the patient must be re-warmed by total immersion into a bath. Under these circumstances, it is best to wait until the patient is hospitalized because shock may occur during re-warming.
- Frozen tissues are painless and appear waxy with a pallid yellowish colour. The tissue becomes painful, swollen and very prone to infection when thawed. Therefore, do not re-warm rapidly if the accident occurs in the field and the patient cannot be transported to hospital immediately. Thawing can take from 15 minutes to 60 minutes and should be continued until the blue pale colour of the skin turns to red or pink.
- If the frozen part of the body has thawed by the time medical attention has been obtained, do not re-warm. Under these circumstances, cover the area with dry sterile dressings with a large bulky protective covering.
- Administer a tetanus booster.
- Alcohol and smoking decreases the blood flow to the frozen tissue and therefore must not be used.

4

Tanks, containment and spill control

4.1 Tanks

For export and import facilities, tankage is necessary for LNG storage. The tank type to be used will depend on a number of factors including land space, quantified risk assessment and national regulations.

However, where LNG import terminals are generally close to population centres, industry, power stations, etc., LNG tanks for these facilities will virtually all be designed as the full containment type as land space is usually at a premium.

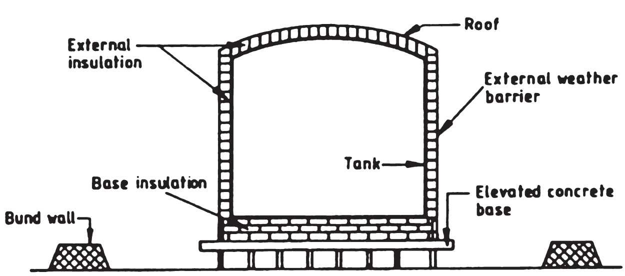
4.2 Aboveground tanks

Aboveground tanks have been the most widely accepted and used method of LNG storage primarily because they are less expensive to build and easier to maintain than underground tanks. There are more than 200 aboveground tanks worldwide, and they range in size from 45,000 barrels to 1,000,000 barrels (7,000 m^3 to 160,000 m^3).

4.3 LNG tank types

The three different tank types are shown below:

Single containment (SIGTTO)

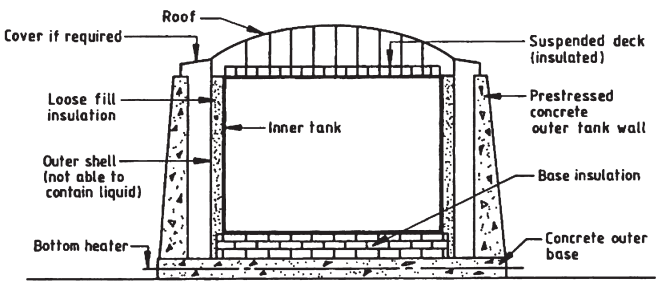


Basic description

The single containment tank inner tank consists of a flat metallic bottom, a cylindrical metal wall built of materials (usually 9% nickel steel) suitable for cryogenic temperatures and with the strength to withstand the hydrostatic load of the LNG at its minimum temperature and maximum storage pressure. They also have an insulation layer with a domed roof supported by an outside vapour barrier or outer tank (usually carbon steel). The insulation below the bottom is usually cellular glass foam. Tank piping penetrations can be through the sides but are usually through the roof of the tank.

A low earthen dike or bund wall surrounds the tank to confine any LNG spill.

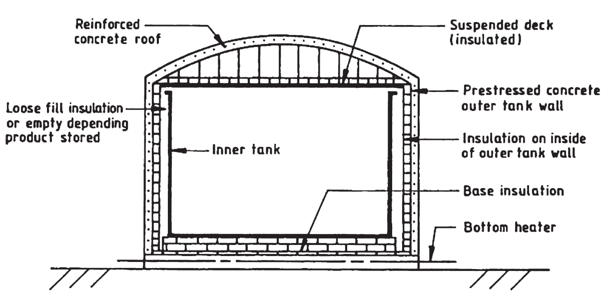
Double containment tank (SIGTTO)



Basic description

The double containment tank consists of the basic single containment tank but with the addition of an outer tank designed to contain the LNG, but not the vapour. The outer tank can be 9% nickel or pre-stressed concrete. In both the single and double containment cases, the roof is not designed to fully contain the liquid. Tank piping penetrations are generally through the tank roof. A full height pre-stressed concrete bund wall or dike surrounds the tank to confine any LNG spill.

Full containment tank (SIGTTO)



Basic description

For a full containment tank, the double containment tank is used but with a strengthened roof that will contain the LNG and vapours completely during any spill. All tank penetrations are through the roof. The outer tank is designed to contain any LNG spill.

A typical full containment tank consists of the following components:

- A concrete tank slab. This may be on the ground with an electric heating coil to protect the ground from frost heave or an elevated slab.
- A 9% nickel open top inner tank.
- A concrete outer tank consisting of a post-tensioned wall connected rigidly to the outer concrete bottom slab, with a roof constructed of reinforced concrete. The inside of the concrete tank is lined with a carbon steel vapour barrier.
- A 9% nickel steel secondary bottom and 9% nickel steel insulated 'Thermal Corner Protection' (TCP). These are linked together. The top of the TCP is anchored into the pre-stressed concrete wall, approximately 5 metres (15 ft) above the base slab. The secondary bottom is placed above a lower system of cellular glass bottom insulation.
- A carbon steel roof liner forming an integral structure with the reinforced concrete roof.
- A suspended inner deck supported by hangers from the concrete roof and roof liner. The suspended deck is made of aluminium, supported by stainless steel hangers.
- A tank insulation system including insulation under the inner tank bottom (cellular glass, below the secondary bottom and, if required, between the secondary bottom and inner tank bottom), insulation between the steel inner tank shell and the concrete outer tank (expanded perlite) and insulation on top of the suspended inner deck (also expanded perlite). The bottom insulation system consists of a dry sand-levelling layer above and below the cellular glass blocks arranged to accommodate a secondary bottom steel liner.

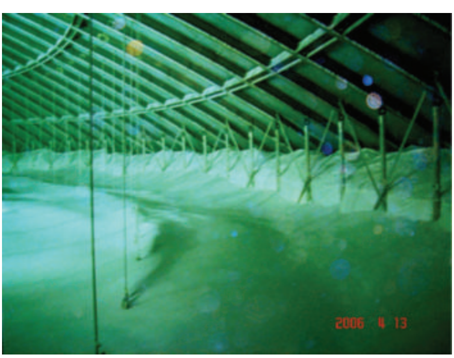


Photo shows expanded perlite in the space above the suspended deck. This perlite is also used in the space between the inner tank and outer concrete tank in a full containment tank.

- Resilient glass fibre blankets are installed to form a compression cushion on the inner tank. The blanket reduces the horizontal pressure effect of the perlite powder. The blanket is securely held against the inner tank shell.
- Submerged pump risers and pumps (including lifting cables from the top of the tube to the pump and junction boxes at the top of the tubes).
- Platform, staircase, walkways, caged ladders, monorails, crane, handrails, etc.

Inner tanks are generally constructed in line with API 620, Appendix Q.

The thermal insulation in a tank, as efficient as it is, will not keep the temperature of LNG cold by itself. LNG is stored as a ‘boiling cryogenic liquid.’ Simply put, it is a very cold liquid at its boiling point for the pressure at which it is being stored.

Stored LNG is analogous to boiling water, only 240°C (470°F) colder. The temperature of boiling water (100°C (212°F)) does not change, even with increased heat, as it is cooled by evaporation (steam generation). In much the same way, LNG will stay at near constant temperature if kept at constant pressure.

This phenomenon is called ‘auto-refrigeration’. Using a tea kettle as an example, so long as the steam (LNG vapour boil off) is allowed to leave the tea kettle (tank), the temperature will remain constant. If the vapour is not drawn off, then the pressure and temperature inside the vessel will rise.

4.4 Tank instrumentation and alarms

Tank instrumentation has similarities with typical flammable liquid storage tank operational requirements. However, there are number of LNG specific requirements. The following is a list of typical instruments and alarms.

- Cool down temperature sensors—tank wall and base.
- Leak detection temperature sensors located in annular space—low temperature alarm.
- High temperature alarm in tank vapour space.
- LNG tank gauging system as follows:
    - Two analog independent servo type level gauges are installed to provide remote readings and high/low-level alarm signals.
    - In addition, each gauge is equipped with two relays allowing high-high and low-low level trips. Local level indication is also installed.
    - A separate multi-point temperature-measuring probe is provided for each level gauge (typically 16 resistance bulbs equally distributed over the measurement range and individually wired to the temperature transmitter).
    - The tank is also equipped with a level temperature density gauge (LTD) that gives the density and temperature at each pre-set level. To detect rollover potential, the LTD and the multi-point temperature transmitters have the capability to detect a temperature difference of 0.3°C (0.5°F) and a density difference of 0.8 kg/m^3 (0.05 lb/ft^3).

- An independent third instrument for high-high alarm and trip.
- Pressure controllers, one adjusting the boil off gas compressor capacity control and the other letting down to the flare header.
- Dial gauges for settlement monitoring during hydrotest.
- Pressure relief valves (minimum of three pilot operated), vacuum relief valves.
- Fire and gas detectors and alarms on the tank roof/platform.

4.5 Internal pumps

Vertical submerged pumps are installed through the roof of the LNG tank in pump wells. Typically three 33% pumps are installed with a spare pump well. Typical discharge pressures are 13–15 barg (188–218 psig). These pumps feed the re-condenser and external HP pumps. They are also used to keep the LNG unloading line cool by continuous circulation of a slipstream from one of the pumps. The pumps are electrically driven with the motor submerged in and cooled by the LNG.

4.6 Power supply to pumps

The pumps are supplied by electrical power through nitrogen purged glands at the top of the tank.

4.7 Leakages into annular space/roof space

In a full containment tank, the suspended deck is not gas tight and therefore the annular space and the roof space will always be in methane service (methane rich) although at a higher temperature than the cryogenic liquid.

4.8 Underground storage tank

Belowground LNG tanks harmonize with their surroundings. Japan and Korea use in-ground LNG storage tanks. Japan has the world's largest LNG in-ground storage tank that has been in operation since 1996. It has a capacity of 200,000 m^3 (7 million cubic ft). There are currently (2005) 61 in-ground storage tanks in Japan.

Underground tanks are buried completely below ground and have concrete caps. This design can minimize risk and the ground surface can then be landscaped to improve the aesthetics of the area. However, they are more expensive to build and maintenance is more demanding than aboveground tanks.

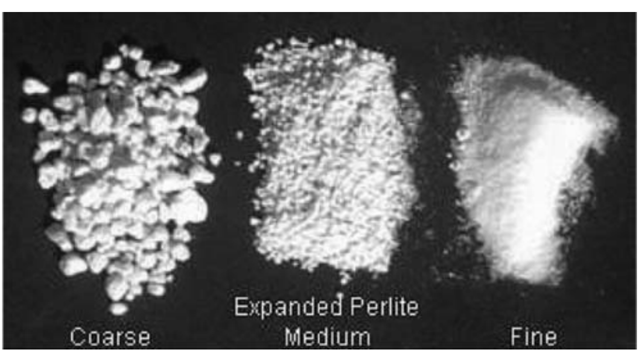
An example of an underground (in-pit) LNG storage tank in Korea. The tank has a double metal shell with an inner and outer tank. The inner tank is made of metal with high resistance to low temperature. Additional insulation of thermal insulating materials and dry nitrogen gas is sometimes used as an inert gas to fill the space between the inner and outer tanks. In-ground tanks are not the same as in-pit tank. The in-pit tank is a proper tank as described above, but the in-ground tank consists of a concrete base and concrete slurry wall sides with insulation and then a stainless membrane covered over with a dome roof. In effect, it is an in-ground container, rather than a tank.

4.9 Insulation

Expanded perlite is used as insulation in the spaces between the inner and outer tanks and in the roof space of tanks.

Perlite is not a trade name but a generic term for naturally occurring siliceous rock. The distinguishing feature which sets perlite apart from other volcanic glasses is that when heated to a suitable point in its softening range, it expands from four to twenty times its original volume.

This expansion is due to the presence of two to six percent combined water in the crude perlite rock. When quickly heated to above 871°C (1600°F), the crude rock pops in a manner similar to popcorn as the combined water vaporizes and creates countless tiny bubbles which account for the light weight and other exceptional physical properties of expanded perlite.



This expansion process also creates the white colouring of perlite. Expanded perlite can be manufactured to weigh as little as 32 kg/m^3 (2 lb/ft^3) making it adaptable for numerous applications. Since perlite is a form of natural glass, it is classified as chemically inert and has a pH of approximately 7.

Perlite concrete blocks have been used by some construction companies for the base insulation of large cryogenic tanks to insulate the base of the tanks between the ground and the bottom of the tank itself. This is necessary to prevent 'frost heave' which can damage the base. The perlite blocks were used because of good load bearing strength and excellent thermal properties. However, they are susceptible to water damage and can degrade and lose their load bearing properties.

For this reason cellular foam glass is often used instead of perlite blocks.

Lightweight insulating concrete blocks are manufactured from a mix of lightweight perlite aggregate, ordinary Portland cement, and special admixtures; and they are reinforced with special steel bars.

Photograph above shows perlite concrete block after curing and ready for use.

4.10 LNG vaporizer units

Each LNG storage tank has send out pumps that will transfer the LNG to the vaporizers. Ambient air, seawater at roughly 15°C (59°F), or other media such as heated water, can be used to pass across the cold LNG (through heat exchangers) and vaporize it to a gas. The most commonly used types of vaporizers are the Open Rack (ORV) and the Submerged Combustion (SCV). Other types include Shell & Tube exchanger (STV), Double Tube Vaporizer (DTV), Plate Fin Vaporizer (PFV), and Air Fin Vaporizer (HAV).

4.11 Open Rack Vaporizer (ORV)

Open Rack Vaporizer (ORV) uses seawater as its heat source. Seawater flows down on the outside surface of the aluminum or stainless steel heat exchanger panel and vaporizes LNG inside of the panel.

Photograph shows an ORV example in an import facility.

Baseload operations use ORVs. Peak shaving operators use the same open rack ORV which has the following features:

- simple construction and easy maintenance;
- high reliability and safety.

4.12 Submerged Combustion Vaporizer (SCV)

This uses hot water heated by the submerged combustion burner to vaporize LNG in a stainless tube heat exchanger. SCV is applied mainly to the vaporizer for emergency or peakshaving operation, but it is also used as a baseload.

An SCV has the following features:

- low facility cost;
- quick start up;
- wide allowable load fluctuation.

Photograph shows an example of an SCV

4.13 Spill control–impoundment/containment

All current regulations require a dike or bund around the LNG storage vessels. Dikes/bunds or some method to direct the flow of LNG is also required in those process areas where a spill could occur.

Most peakshaving facilities have relatively low height earthen dikes. Higher dike/bund height can be used to reduce the amount of land needed for exclusion zones. Some facilities have utilized a dike/bund that is the full height of the tank.

The dike dimensions depend on the volume requirements stated in the code (110 to 150% of tank volume) and on the requirement that the trajectory of a leak at the upper liquid level does not overshoot the edge of the dike. Therefore, current regulations and design assure that if there was a leak from the tank, the full tank contents are retained by the impoundment.

The terms 'impoundment' or 'containment pit' are used in the LNG industry to identify spill control designed to limit the liquid travel in case of a release. It generally refers to spill control for tank contents, but may also refer to spill control for LNG piping or transfer operations, including ship to shore and truck loading. Earthen or concrete dikes/bunds may provide impoundment or containment surrounding an LNG container. These may be relatively low (1.5–3 m (5–15 ft) in height) or up to the full height of the tank. The low dikes/bunds are typically earthen while the high dikes are concrete.

The regulations for large tanks require that the impoundment be not less than 110% and up to 150% of the tank contents. Having the minimum impoundment floor area reduces both the vapour dispersion and thermal radiation hazards; hence, high dikes/bunds tend to reduce risks.

The impoundment materials and configuration have a significant effect on the formation and dispersion of LNG vapours. The thermal radiation hazard also depends on the surface area of the impounded LNG pool, if ignited. These factors suggest the design of minimum floor surface area in order to minimize LNG pool surface area.

The impoundment around LNG storage tanks and the spill control and impounding around equipment containing LNG serves the obvious purpose of preventing uncontrolled flow of LNG and, in particular, preventing it from entering sewers and storm drains. The shape of the impoundment area and its floor construction material have a tremendous impact on the rate of vapour generation in the event of a spill.

4.14 Spill control objectives

If there is a release of LNG, it is important to control the release and minimize the effects of the spill. The effects to be considered are:

- restricting flow to a safe location either by using drainage channels or spill containment pits;
- reducing the vapour generation rate either by limiting the surface area and/or by using firefighting foam for vapour suppression;
- reducing the size of fire should the release be ignited, by use of firefighting foam to reduce flame size and radiant heat levels.

All of these objectives can be met with careful design of the impoundment.

The main aim is to limit the area wetted by the liquid and to accumulate the spill in as small an area as possible.

Vapour generation reduction

The vapour generation rate is dependent on the amount of wetted surface area and the characteristics of the surface. The relevant surface material characteristics are density, thermal conductivity and specific heat. To reduce the vapour dispersion, each of these characteristics must be minimized. Some facilities use a lightweight insulation that is weather resistant to insulate transfer areas and dikes.

Fire size reduction

The size of a fire is primarily dependent on the surface of the LNG pool. A low surface area with a deep sump is beneficial. The fire-burning rate is directly proportional to the LNG evaporation rate where the primary source of heat for this evaporation is the thermal radiation from the fire itself.

Retention basins/pits

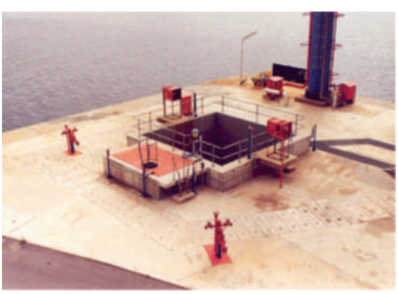
The design and capacity of containment/impoundment for LNG primarily covers tank or large volume contents of LNG and is covered in national standards including NFPA and EN. For spills from pipework etc on site, spill retention basins (pits) are necessary. These retention pits should be located in as safe an area as possible with minimum adjacent or nearby plant and equipment that could be affected by flame impingement or radiant heat. Similarly, for vapour migration, the pits should be located in as safe an area as possible to minimize the potential for vapour to enter confined spaces or possibly reach potential ignition sources.

Typically, the retention pit design parametres should include the following criteria:

- The capacity shall be equal to or greater than the amount of liquid which would be spilled by breakage of the pipeline with the highest leakage rate for the time necessary for detection and for interruption of flow.
- An impounding basin shall be open to the atmosphere.
- A means for limiting evaporation and reducing the rate of burning of ignited spills and consequences shall be provided.

Impounding areas for LNG in which rain or firewater can collect shall include a means for removing it to ensure that the required volume is maintained and to prevent flotation of storage tank or tanks. The water shall drain to an extraction sump within the impounding area and be removed by pumping or by gravity flow. Retention pits shall also be kept drained. A reliable method shall be provided for preventing spilled LNG from being discharged from the contained area or pit through the water drainage system.

Photograph on the left shows at left of centre a jetty retention pit for spills at the loading arm/piping area. Spilled LNG would be channelled to this pit. The 'bridge' channel can be seen between the jetty head and the pit itself. The pit has high-expansion foam unit provided to reduce either vapour or fire size. (*Photo courtesy BBG*)



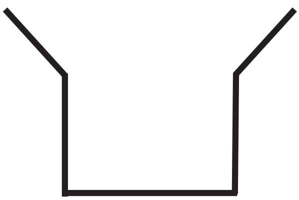
This retention pit is on the main jetty head. There are several exposures adjacent with the ship loading relatively close by. It is not an ideal location for a pit for marine loading spills, where dolphins could be considered. The design objective of the fire hydrants is unclear, since it is highly unlikely that hose handlines would be used instead of the high-expansion foam units due to high radiant heat levels. (*Photo courtesy Resource Protection International*)

This onshore liquefaction and export facility retention pit has drain channels from two tanks running into it. The nearby roads would need to be barred to traffic to prevent ignition. The high-expansion foam systems should have cryogenic detection either automatically actuating the foam system or for operators in a control room to remotely actuate the foam system. (*Photo courtesy Resource Protection International*)

For retention pits, there are two aspects which have come to light during the BP LNG Fire School, and which need to be considered for their design where high-expansion foam system are to be provided, as follows:

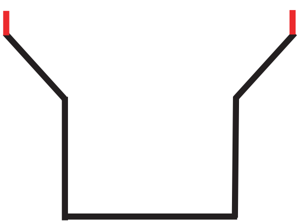
Top sides of containment pits, above the maximum liquid level, should be sloped at an outward angle such that high expansion foam will spread over this area and offer a more effective blanket for the LNG vapours underneath.

This concept is shown by the sketch below.



Unless the slope from the edge of a containment pit is away from the pit, moderate to heavy rainfall, or cooling spray/water curtain water run-off can enter a containment pit easily and increase either the vaporization rate or the fire size due to increased vaporization.

One method of avoiding this problem is to use a simple low-level kerbing arrangement around the sides of the top of the pit, as shown below.



This kerbing only needs to be high enough to prevent run-off into the pit and therefore only of the order of 25–37 mm (1–1.5 inch) high. It is simply a barrier to water inflow but should obviously have the same fire resistance as the pit itself.

The same kerbing considerations should be applied for drainage channels.

Pit depth

It is obvious from a number of tests and exercises conducted at the BP LNG Fire School that a deeper containment pit, rather than a shallow pit, increases the amount of direct radiant heat, such that the concrete walls begin to spall within a few seconds after ignition of the LNG.

It is concluded that this is most likely due to the significantly greater depth/height of the pit concrete walls, which amplifies the intensity of heat build up and which in turn reflects back on to the LNG within the pit and further increases vaporization.

LNG fire in a 1.2 m (4 ft) deep pit. Note the reduced flame height due to shallower pit depth, although the smaller surface area also reduces flame height.

LNG fire in a 2.4 m (8 ft) deep pit. Note the significantly higher flame here compared to the 1.2 m (4 ft) deep pit photograph. The radiant heat from this deeper LNG pit fire was very intense compared to the other shallower pits.

4.15 Materials

This section considers some of the issues regarding materials of construction, especially of LNG tanks. A release from an inner tank shell could occur from one of the following situations:

Material of insufficient strength

Existing codes require material testing and certification and these also have significant safety factors. Completed liquid containing tank must be hydrotested to the indicated liquid levels.

Loss of material ductility at low temperatures

Existing codes require material selection to prevent embrittlement and testing further reduces potential for incorrect materials.

Embrittlement protection should be provided to:

- protect equipment and main structural supports from localized fire incident minimizing escalation and endangerment of emergency response personnel;
- protect the main structural members from cold-splash brittle failure and resulting overall collapse.

In this demonstration of embrittlement, a fireman's boot with steel toe cap is taken from an LNG pit. *Pictures courtesy Resource Protection International*

Using a heavy hammer, without much force, the steel cap is shattered along with the rubber boot itself.

Remains of the boot and steel cap.

A carbon steel pipe is next taken from the LNG pit.

Using the same hammer, without much force, the pipe easily breaks up due to embrittlement.

Remains of the steel pipe in the foreground.

Material defects

Steel plate may have laminations that could leak, but would be unlikely to grow larger.

Poor welds

All welds must be inspected and critical welds must be 100% radiographed. Use of the wrong weld material may result in weld failure. Post weld material verification must be appropriate and is required by codes.

Seismic loading

Tanks are conservatively designed for earthquakes. Metal tanks may be vulnerable at the welded joint of the shell-to-footer plate. Metal tanks may sustain 'elephant foot' yielding. Special tank designs are required and tank construction is not permitted in some seismic locations. (Refer to USA 49 CFR 193.2061)

Current tank designs have proved safe for 30 years. Therefore, the variables impacting safety are proper construction, materials and techniques.

The potential weak link in construction is the third party verification of radiography, which must be part of a comprehensive quality assurance (QA) audit program. The most critical weld in an LNG tank is the double fillet weld joining the bottom course of the inner tank shell to the footer plate. Fillet welds are difficult to radiograph and in this case, only an in-process inspection, such as dye penetrate testing, is feasible. This requires special attention in the QA program.

The inner tank floor is typically fabricated (in place) with large sheets of 3/16" (5 mm) 9% nickel alloy. The floor is joined by lap welds and supported from underneath by the load-bearing insulation. Although lap welds are more vulnerable to defects and defect development, the inner tank floor is essentially a membrane and not a structural element.

As the understanding of metallurgy and fracture mechanisms have increased, it is recognized that the catastrophic inner tank failure, although theoretically possible, was not a credible accident theory for a tank designed and built to current standards.

The focus has now therefore shifted to a 'design accident' which specifies a release rate and duration dependent on the tank configuration.

The table below highlights typical materials used for cryogenic liquids.

Liquefaction temperatures of gases and used types of parent materials			
Gas	Liquefaction temperature (°C)	Liquefaction temperature (°F)	Type of parent material used
Ammonia	-33.4	-28.1	Carbon steel
Propane (LPG)	-42.1	-43.8	Fine grain Al-killed steel
Propylene	-47.7	-53.9	2.25% Ni steel
Carbon disulphide	-50.2	-58.4	
Hydrogene sulphide	-59.5	-75.1	3.5% Ni steel
Carbon dioxide	-78.5	-109.3	
Acetylene	-84	-119.2	
Ethane	-88.4	-127.1	
Ethylene (LEG)	-103.8	-155	5-9% Ni steel
Krypton	-151	-239	
Methane (LNG)	-163	-261	
Oxygen	-182.9	-297	
Argon	-185.9	-303	
Fluorine	-188.1	-307	
Nitrogen	-195.8	-320	Austenitic stainless steel
Neon	-246.1	-411	
Heavy Hydrogen	-249.6	-417	Al alloys
Hydrogen	-252.8	-423	
Helium	-268.9	-452	
Absloute zero	-273.18	-459.7	

4.16 LNG plant basic safety measures

NFPA and EN standards dictate the minimum safety requirements and in the case of the EN standards, risk assessment is used to identify hazards and determine protection and safety requirements.

The following are some basic requirements:

- For liquefaction plants, leaks of LNG and hydrocarbon liquids such as Natural Gas Liquid (NGL) and refrigerants produce flammable vapour clouds denser than air. The plant shall therefore be designed to eliminate or minimize the quantity and frequency of accidental and planned emissions of these fluids.
- This shall be achieved by using a Safety Management System approach during design, procurement, fabrication, construction and operation of the plant to ensure that the best available rules of technology are implemented.

Particular consideration shall be given to the following:

  - wherever possible plant and equipment containing flammable fluid shall be located in the open; however,
  - maintenance and climatic conditions will affect this decision;
  - plant layout shall be designed to minimize congestion;
  - appropriate piping flexibility to suit all operating conditions;
  - the number of flanges in pipe runs shall be minimized by using welded inline valves where practical.

- Where flanges are used qualified gaskets, suitable for the joint and services, should be selected or flanges should be oriented so that if a leak occurs the jet stream shall not impinge on nearby equipment.
- The location of relief valve tail pipes shall be such as to minimize hazard.
- Design pressures shall leave a sufficiently wide margin above operating pressures so as to minimize the frequency of the lifting of relief valves.
- Pumps with high integrity seals or submerged pumps and motors shall be used for LNG.
- It is recommended that galvanized surfaces are located so as to avoid the possibility of molten zinc contaminating austenitic stainless steel piping and equipment in the event of a fire possibly leading to brittle fracture or rapid failure.
- Attention should be paid to the installation of zinc and aluminium above unprotected steel and copper systems. If aluminium or zinc is heated for a long time with a steel or copper object, that object could develop pits or holes from alloying during future operation. This phenomenon will not be instantaneous, but would affect the integrity of the plant in future operation.
- Isolation valves shall be fitted as close as possible to the nozzle, outside the skirt, of process liquid outlets of pressure vessels containing flammable liquids such as hydrocarbon refrigerants and LNG. These isolation valves shall be capable of remote operation by push button in safe location or automatically by the Emergency ShutDown System.
- Irrespective of the means for recovery of boil-off gas which might exist elsewhere (for example, re-liquefaction, compression), the vapour space of the tank shall be connected to a flare/vent or safety valve which is capable of discharging flow rates from any likely combination of the following:
  - evaporation due to heat input in tank, equipment and recirculation lines;
  - displacement due to filling at maximum possible flowrate or return gas from carrier during loading;
  - flash at filling;
  - variations in atmospheric pressure;
  - desuperheaters;
  - the recirculation from a submerged pump;
  - rollover.

4.17 Potential leaks and spills

LNG leaks are possible in a wide range of operating areas. Some examples of potential leak sources are as follows.

Piping

Leaks are likely to occur at piping flanges, fittings, welds and pipe penetrations in vessel walls. Typically, the piping from the jetty to the tanks should have minimum flanges to reduce spill potential.

Valve packings

Although valves in LNG service are or should be specifically designed for cryogenic temperatures, when plant and equipment are cooling down, metal parts obviously contract significantly. It is then that LNG leaks may occur in valve packings. Where extended bonnet valves are used for LNG service, packings leaks can be predicted by an abnormal accumulation of frost on the extended bonnet.

The height of the frost will indicate the scale of the leak problem and will give a good indication of leak potential. Tightening of the packing may serve to prevent liquid leaks.

Transfer hose and spool pieces

Transfer of LNG from one container to another can involve both a liquid and vapour/liquid return line. These lines become cold during the transfer process that may result in leakage at the connections where threaded or flanged joints can leak. Leaks in spool pieces can also occur in the same manner. The hose itself can also develop holes.

Once transfer operations are completed, LNG or cold vapour may be isolated in transfer hose (or piping) as a result of valve shut-off procedures.

Once the liquid vaporizes and the vapour warms, pressure in the hose or line will increase. Normal procedures require some form of venting to prevent excessive pressure build-up.

If the procedure calls for venting to atmosphere, it must be remembered that as well as cold gas/vapour, there will also be liquid entrained in the vent stream. Care must be taken to control the venting so that the liquid will not contact operators or maintenance personnel carrying out the venting operation.

Sample lines and containers

When samples of liquid are taken the procedures for doing so should always minimize potential for spills from either the sample lines or containers. Procedures should also specify the appropriate sample equipment and PPE for personnel. It must always be remembered that personnel are obviously present when samples are taken and therefore they must be protected against liquid LNG contact.

Gas phase piping

Cold gas leaks can occur in the piping and equipment associated with the liquefaction, storage and vaporization of natural gas.

In the *liquefaction* process, leaks may involve not only the natural gas stream but also refrigerants used in the process. The piping connecting the liquefaction and storage tanks commonly carries liquid to the storage tank for final pressure letdown.

Other pipes carry return, flash and boil-off gas from the storage tanks.

Vaporizers

For import facilities and peakshaving facilities, the area where the LNG is vaporized requires extra consideration since this area involves not only high flow rates and pressures but also often the transition from cryogenic pipe materials to ambient service materials.

If a vaporizer and its controls were to malfunction and the operator fails to respond to alarms correctly or in time, cold gas or liquid could reach the ambient service piping, despite automatic trip devices and interlocks, causing embrittlement and failure.

Relief valve vents

RVs are designed to protect vessel and piping systems from pressures above specified limits. The discharge from RVs must be directed to minimize personnel hazards and also to minimize equipment and plant impact on discharge. Where discharge may involve cold gas, it must be noted that the vapour will be generally heavier than air at temperatures below −121°C (–186°F). Discharges from RVs to atmosphere will usually be visible in the form of a vapour cloud.

4.18 Potential releases–cryogenic issues

Cooldown of piping and equipment

Piping, when cooled by a cryogenic liquid, has a tendency to bow up due to cooling of the bottom of the pipe before the top. This bowing can cause excessive stress if it is not considered in the design.

Bowing can be controlled both through proper design of the piping system and specification of cooldown procedures.

Excessive piping stress can also result from non-uniform or rapid cooling of thick sections at anchor points or in equipment. Rapid cooling can also cause leaks at flanged joints.

Internal blockage

Ice, hydrates and solid carbon dioxide can form in gas streams as they are being cooled unless the gas has been properly treated for removal of water and CO_2. Excessive build up of these solids in valves and heat exchangers can lead to partial blockage or in extreme cases, complete blockage.

External ice damage

Ice can build up in insulation having an inadequate vapour barrier, which allows the migration of water into the insulation. This ice will cause a breakdown of the insulation and a significant increase in heat transfer and may cause structural damage to the piping and equipment or structural supports. Ice build up on exposed un-insulated surfaces may also cause structural damage, especially by preventing movement of piping relative to supports or overloading.

Blocking in LNG

As LNG heats up it expands and if confined to a fixed volume it can generate extreme pressures. Therefore, blocking LNG into a fixed volume of piping or equipment, such as between two valves, must be avoided.

4.19 Tankage and thermal radiation

Each LNG container or tank is required to be within a dike or impoundment area that is large enough to hold 110 to 150% of the entire contents of the tank.

Different countries have different standards and codes of practice for tankage and thermal radiation limits, including Japan, Australia, Canada and Europe.

In the USA, 49 Code of Federal Regulations (CFR), Part 193.2057 regulations specify that each LNG container or LNG transfer location have a thermal exclusion zone beyond the impoundment, which includes an area calculated from the top inner edge of the spill impoundment area.

These exclusion zones must be large enough so that the heat from an LNG fire does not exceed a specified limit for objects and activities. Such ‘targets’ must be located outside the thermal exclusion zone. This exclusion zone must be owned or controlled by the operator of the LNG facility. The thermal exclusion zone formula and heat flux factors used for calculation of the exclusion zone are described in 49 CFR Part 193.2057.

The two parts of determining the thermal radiation zones are to calculate the strength of the thermal radiation source (essentially the size of the fire), and the strength of the radiated heat as a function of distance from the heat source.

The regulations specify four levels of thermal radiation (flux) that are the boundaries for the four thermal exclusion zones. The units for thermal radiation are British thermal units per hour per square foot (Btu/hr-ft^2) or Kilowatts per square meter (kW/m^2). A Btu is the amount of heat required to change the temperature of one pound of water one degree Fahrenheit. The amount of heat would be received by one square foot of surface area directly facing a fire. As a point of reference, the thermal radiation flux of strong sunlight on a clear day is approximately 300 Btu/hr-ft^2 or approximately 1 kW/m^2.

The four thermal exclusion zones are based on thermal flux levels, which would be a potential risk to different kinds of ‘targets’ or ‘occupancies’. The exclusion zone for each of these kinds of occupancies is determined by calculating the distance from the LNG impoundment to the limiting thermal flux. These boundaries are represented as ‘isopleths’, which are lines of constant thermal flux surrounding the impoundment that is assumed to be the ‘pool fire’.

The four thermal flux levels determining the exclusion zones are listed below:

Thermal Flux Btu/hr–ft^2	**Hazard**	**Prohibited Occupancies**
1,600 (5 kW/m^2)	Human Exposure. Cause discomfort immediately, increasing pain in 15 to 30 seconds. Blistering of unprotected skin thereafter. People not disabled can take shelter or move away from the fire to protect themselves. Flux level is not life threatening provided there is means of escape.	Outdoor areas occupied by 20 or more persons during normal use.
4,000 (12 kW/m^2)	Combustible materials will ignite with sustained exposure. Property loss.	Buildings used for residences or occupied by 20 persons, or non-fire resistant structures of exceptional value or potential hazard.
6,700 (21 kW/m^2)	At this level fire resistant structures may become ineffective with long exposure.	Buildings of exceptional value or potential hazard. Public streets, highways and railroad mainlines.
10,000 (32 kW/m^2)	At this level, steel structures begin to loose strength.	Structures not part of the LNG facility and any property outside the facility's right-of-way.

For design purposes and code compliance, validation of the calculation methods from the code must be used. The code calculations are complex but can be easily performed by using the GRI sponsored 'LNG FIRE' or equivalent validated computer model and program. The original approach for these siting provisions was to consider existing 'off site' targets, implying they were not owned or under the control of the facility owner. A further implication was that the facility siting would not be invalidated by subsequent encroachment of new occupancies.

Currently (2006), the interpretation is that the facility must either own or control the properties within the exclusion zones to preclude new occupancies that would be prohibited by the thermal exclusion zones.

For smaller LNG facilities, other LNG codes, such as NFPA 59A, also deal with the siting and impoundment of LNG storage containers in a similar manner.

5

Jetties and marine facilities

5.1 Jetties

LNG jetties should have the same fire protection as LPG jetties insofar as elevated firewater cooling monitors are concerned. The elevation of the monitors will depend on the size of ship and height of loading manifold.

The Oil Companies International Marine Forum (OCIMF) document *Guide on Marine Terminal Fire Protection and Emergency Evacuation* gives guidance on the capacity of monitors for gas terminals and the Society of International Gas Carriers and Terminal Operators (SIGGTO) *Liquefied Gas Fire Hazard Management* manual also gives design considerations for jetty fixed monitors.

Typically, the firewater supply for the jetty monitors should be capable of between 150 m^3/h (320,000 ft^3/h) and 350 m^3/h (740,000 ft^3/h), depending on ship size. Such monitors should be remote controlled, given the potential for high radiant heat levels.

Elevated cooling water monitors may require the towers to have cooling spray protection to ensure they will continue to function under fire conditions. *Photo courtesy Resource Protection International*

Dry powder systems may also be provided at jetties. This is covered more under Chapter 9—Spill and fire control measures. Dry chemical systems should follow NFPA 17.

Jetty elevated monitor streams should be capable of reaching the fire hazard area (ship manifold and loading arms area under all wind conditions). This may require more than two monitors in practice. (*Photo courtesy Resource Protection International*)

Firewater systems for jetties should consider access for emergency vehicles and fire hydrant outlets to enable fire vehicle connection. This would not be a normal response to manifold LNG fires or gas clouds, but is necessary in case of a ship internal compartment fire. Emergency vehicles lay by, passing area or turning point should also be considered.

To allow firewater to be supplied to a ship fire mains for internal firefighting, a ship-to-shore international firewater connection should be provided at a suitable location at the jetty. This should follow the OCIMF guidance.

Fire tugs

Fire tugs should have a United States Coast Guards (USCG) or Lloyds Classification for firefighting (Fi-Fi). The table below highlights the Lloyds Classifications and capabilities.

Fi-Fi Classes	Class I	Class II		Class III
Monitors	2	3	4	4
Monitor (m^3/h) (US gal/min)	1,200 (5,250)	2,400 x 3 = 7,200 (10,500 x 3)	1,800 x 4 = 7,200 (8,000 x 4)	2,400 x 4 = 9,600 (10,500 x 4)
Fire pumps	1–2	2–4		2–4
Total pumps capacity m^3/h (US gal/min)	2,400 (10,500)	7,200 (32,200)		9,600 (42,000)
Fire pumps fuel oil capacity (hours)	24	96		96
Minimum throw of water monitor stream length m (ft)	120 (390)	150 (490)		150 (490)
Minimum stream height (m)	45 (145)	70 (230)		70 (230)

Tugs or vessels with water monitors can sometimes be incorrectly identified as Lloyds or USCG Classification Fi-Fi tugs when, in fact, the tug may have no classification whatsoever. In order to have, for instance, a Lloyds classification and approval, a tug or vessel must have the firefighting capability as set out in the table on page 45.

Typically but not always owned by port authorities, fire tugs should have a recognized classification. Demonstrations of their capability should be arranged if there is any doubt over their capability. *Picture courtesy Resource Protection International*.

The length of a fire tug water stream throw is measured horizontally from the mean impact area to the nearest part of the vessel when all monitors are performing in a satisfactory manner simultaneously.

Height of stream throw is measured vertically from sea level to mean impact area at a horizontal distance at least 70 m (230 ft) from the nearest part of the vessel.

The fire pump's fuel oil capacity is for continuous operation of all monitors and must be included in the total capacity of the vessel's fuel oil tanks.

The actuation and movement control of the monitors must be remote with the control station in a protected area or control room with a good general view as well as locally operable in manual mode at each monitor. At least two of the monitors must have a fixed arrangement to enable dispersion of the water stream/jet possible. This simply means that some form of jet conversion to spray must be provided. Valve controls must be designed to avoid water hammer.

Evacuation

Emergency evacuation and escape routes should follow the OCIMF guidelines. In some cases, it may be necessary to consider water spray curtains to protect against radiant heat during evacuation. In extreme cases, consideration may need to be given to fixed barriers to protect against radiant heat during evacuation.

5.2 Marine LNG tankers

Since the first voyage of the Methane Pioneer in 1959 from Lake Charles, Louisiana, US, to Canvey Island, United Kingdom, safety systems on LNG carriers and the training of the crews that operate the vessels have been evolving.

The safety systems aboard an LNG carrier are required by the following:

- International Convention for the Safety of Life at Sea (SOLAS) 1974;
- IMO International Gas Codes (IGC);
- Flag State Regulations;
- Classification Society Rules.

In addition to the required safety systems on board LNG carriers, additional safety systems have been installed as a result of recommendations from the Oil Companies International Marine Forum (OCIMF) and the Society of International Gas Carriers and Terminal Operators (SIGGTO).

Training of the LNG carriers crews is required by the International Maritime Organization Standards of Training, Certification and Watchkeeping (STCW); Flag State regulations; operating and chartering companies requirements. The International Maritime Organization specifies standards for the training of ship's crews in the handling of Liquefied Gases but a SIGGTO project to create minimum LNG competency standards for cargo operations as a best practice training standard has resulted in the LNG competency standards being published in November 2005.

These competencies have been welcomed by the industry since for the first time, minimum suggested competencies have been laid down for cargo operations. Employing and training companies now have a framework around which they can deliver specific training for officers employed on LNG carriers.

The competency standards document full title is *LNG Shipping Suggested Competency Standards Guidance and suggested best practice for the LNG industry in the 21st century. (First Edition November 2005).*

The following is a brief description of LNG carriers, their safety systems and the safety checklist used in LNG terminals to help ensure the safe berthing and transfer of LNG between the LNG carrier and terminal.

5.3 LNG carrier cargo tanks

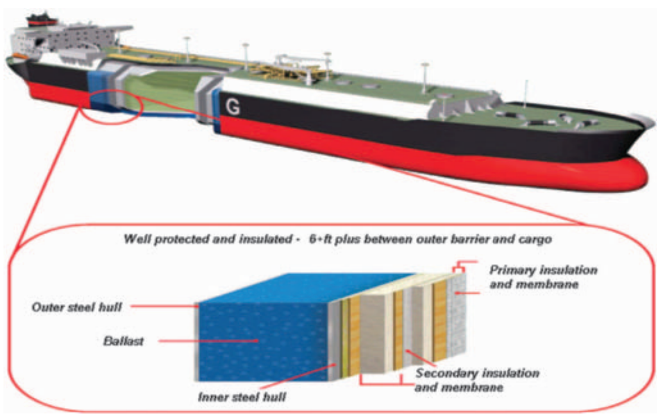
There are three main types of cargo tanks that are used aboard LNG carriers; membrane tanks which are predominantly of the Gaz Transport or the Technigaz system design, Kvaerner Moss design which is a spherical tank and the IHI self-supporting prismatic type B tank.

The above cargo tank systems serve two primary purposes:

- to contain the LNG cargo at or near atmospheric pressure at a cryogenic temperature of approximately −160°C (–256°F);
- to insulate the LNG cargo from the outer hull by ensuring a minimum distance from the sides and bottom of the hull per the IGC.

At −160°C (–256°F), ordinary steels are susceptible to brittle fracture. In consideration of this, all three LNG tank designs require a secondary barrier which is designed to prevent the LNG from contacting the ships structure and exposing the steel to unsafe temperatures in the event of a leak from the primary containment. The secondary barrier for the membrane vessels surrounds the whole cargo tank while the secondary barrier for the Kvaerner Moss and prismatic type B tanks are only a partial barrier.

BP's Trader Class (Technigaz membrane cargo tanks) exceeds the IGC Code minimum distance on the sides and bottoms of the cargo tanks. A cutaway view of the British Trader class vessel is shown below.



5.4 Cargo tank pressure control

The IGC Code requires that LNG carriers have a pressure control system in place to keep the cargo tanks below the maximum allowable relief valve setting of the cargo tanks.

The pressure control system can either be a mechanical refrigeration system that will re-liquefy the boil-off vapour or a vapour collection and gas burning system that will send the boil-off vapour to the ship's engines or boilers for fuel. The IGC Code also allows a flag state to allow other types of pressure control such as venting the boil-off vapour to atmosphere. In the United States venting is not allowed as a means of pressure control except in an emergency.

The IGC Code requires that all LNG cargo tanks with a capacity greater then 20 cubic metres (5,300 US gal) be fitted with at least two pressure relief valves. The relief valves are sized so they can handle either the maximum capacity of cargo tank inerting system or vapour generation rate of the cargo tank due to fire exposure. The relief valves exhaust via a common header to atmosphere via vent risers.

The vent risers should be provided with drains that allow for draining of rainwater. An accumulation of water in the vent risers could affect the relief valves operation. In addition to relief valves for the cargo tanks any piping that could be blocked in with LNG must have a relief valve that allows for the expansion of the LNG. The relief valves would normally be relieved back to a cargo tank.

5.5 Pressure, temperature and gas monitoring

The IGC Code requires that the cargo system be monitored for pressure, temperature and gas leakage. Cargo tanks, cargo pumps, gas compressor discharge and liquid and vapour lines are all areas that should be monitored. In addition to over-pressurization it is important to monitor the cargo tanks for vacuum as the cargo tank relief valves on this condition would allow outside air into the system that could create an explosive atmosphere.

Temperature monitoring is required by at least two devices in the cargo tanks. One of these devices is placed in the bottom of the tank and another will be located below the upper fill level of the tank. Additional temperature monitors are recommended so that during cool-down and warm-up of the cargo tanks the tanks are not subject to abnormal thermal stresses.

In addition to temperature monitoring of the cargo tanks the secondary barrier is also monitored for temperature to ensure that the cargo tank integrity is not comprised, which could expose the ship structure to temperatures for which it is not designed.

A fixed gas detection system is required to monitor spaces that gas could leak into. Spaces monitored should include:

- enclosed spaces adjacent to the cargo tank such as inter-barrier and hold spaces;
- cargo compressor room and its electric motor room if applicable;
- cargo control room unless it is classed gas safe;
- airlocks;
- engine room gas supply pipelines and burner platform vent hoods.

The fixed gas detection system must be equipped with audible and visual alarms which display in the cargo control room, wheelhouse and where the gas detection system is located. Intervals between sampling of individual spaces should not exceed 30 minutes and the system should alarm when the gas concentration reaches 30 per cent of the lower flammable limit.

5.6 Gas dangerous zones

The IGC Code clearly defines areas of the ship that are regarded as gas dangerous zones.

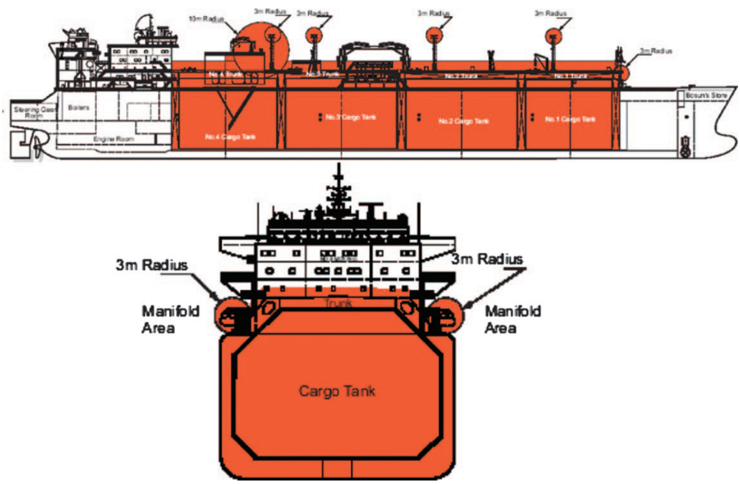
Zones include the following spaces:

- 3.0 metres (9 ft) from any cargo tank outlet, cargo vent, valve, flange, compressor room access or vent and forward or aft of the cargo deck;

- 2.4 metres (8 ft) above the cargo deck or from the cargo containment systems which are exposed to the weather.

Within these zones all equipment needs to be safe for purpose, including that electrical equipment is intrinsically safe, flameproof type equipment and pressurized enclosures type equipment.

The following diagrams are examples of the gas dangerous zones on a ship.



5.7 Emergency shutdown systems

Emergency shutdown (ESD) systems are designed to put the ship in a safe state in the case of an emergency. During cargo transfer operations, both the ship and terminal, liquid and vapour systems are interconnected so it is recommended that there be a linked ESD system between the ship and terminal.

The system should be initiated by the following emergencies:

Ship	Terminal
Manual trip.	Manual trip.
Automatic trips	**Automatic trips**
• Shutdown signal from the shore;	• Shutdown signal from the ship;
• High filling level of any cargo tank;	• Overfilling of a receiving tank;
• Power loss to valve controls;	• Power loss for hard arm manoeuvring;
• Loss of control air or hydraulic pressure;	• Power loss to emergency release system for the hard arms;
• ESD logic failure;	• ESD logic failure;
• Fire in a cargo area;	• Fire in the terminal area;
• Loss of electrical power;	• Loss of electrical power;
• Low cargo tank pressure.	• Excessive ship movement at the berth;
	• Activation of the Power mergency Release Couplers (PERC).

The ESD system should initiate the following immediate actions.

On Ship	On Terminal (loading)
• Send shutdown signal to shore;	• Send shutdown signal to ship;
• Trip ships cargo and spray pumps;	• Trip loading pumps;
• Trip ships gas compressors;	• Close terminal’s ESD valves.
• Close ships ESD valves.	**On Terminal (receiving)**
	• Send shutdown signal to the ship;
	• Close terminal’s ESD valves.

Emergency shutdown systems are generally linked by the following different methods:

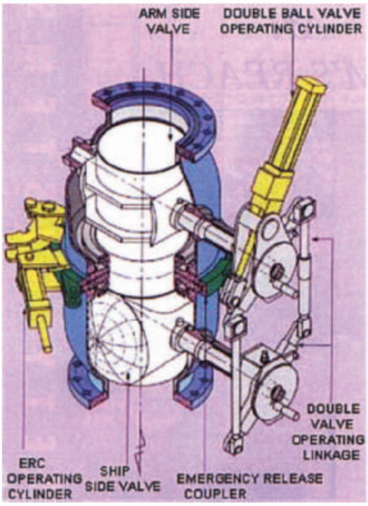
- pneumatic;
- electrical;
- fibre optics.

A pneumatic system will only activate the ESD. Electrical and fibre optic systems in addition to carrying an ESD signal are commonly used for ship/shore telephones, external telephone and transmission of mooring tension monitoring system data.

5.8 Hard-arms and Power Emergency Release Couplers (PERC)

Hard-arms are used for the connection of the ship and terminal as they are inherently safer than hoses. A picture of hard arms connecting the ship and terminal is shown below.

In order to protect both the ship's manifold connection and the terminal's hard arms a Power Emergency Release Coupler (PERC) is fitted in most hard arm installations. The PERC is comprised of two ball valves and an emergency release coupler. If the vessel moves outside the normal operating envelope for the hard arms an ESD will be initiated and cargo transfer will be stopped. Further movement of the vessel outside of the operating envelope will activate the emergency release system; the ball valves will close and the emergency release coupler will operate. One ball valve remains attached to the ship and the other stays attached with the hard arm. The PERC system may also be activated by a manual push button. The system is designed so minimum liquid is trapped between the valves and consequently would be spilled upon release. A picture of a PERC is shown on page 53.

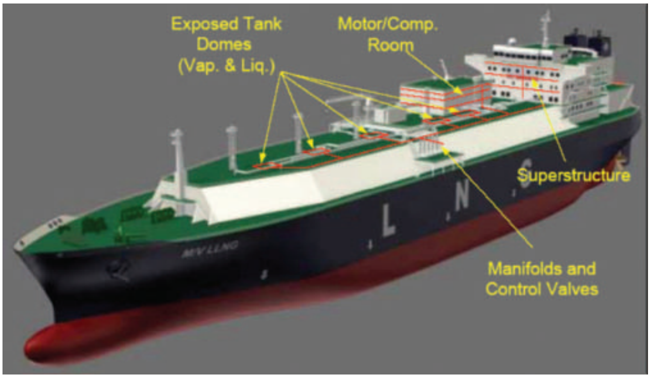


5.9 Firefighting systems

LNG carriers have additional firefighting capabilities compared to conventional tank vessels and some of these capabilities are as follows.

- The fire main system operates at a higher pressure in order to give a better water spray pattern. The fire main system will have additional isolation valves. The fire pumps are capable of remote starting and any part of the cargo containment system must be able to be reached by at least two jets of water.
- Compressor rooms are fitted with fixed carbon dioxide systems.
- Fixed dry chemical powder is fitted for firefighting in the exposed cargo area with at least two hoses or monitors capable of reaching the manifold area. Dry chemical monitors have a discharge rate of not less than 10 Kg/sec (22 lb/sec) and a range of 10 to 40 metres (30 to 120 ft) depending on capacity. Dry chemical hoses must have a discharge rate of at least 3 Kg/sec (6.6 lb/sec) with the rate designed so that one man can operate the hose. These systems shall be independent with the monitor capable of remote control operation with minimum powder storage of 45 seconds of operation.
- Water spray systems are used for fire protection, cooling and personnel protection. The system must be able to cover the following areas: exposed cargo domes; cargo piping and control valves; deck storage tanks for flammable and toxic products and the boundaries of the accommodations; compressor room; cargo control room and any store rooms that contain flammable materials that face the cargo area. The water spray system must be capable of covering the above areas simultaneously and at a rate of 10 litres/m^2/min (0.25 US gal/ft^2/min) for horizontal surfaces and 4 litres/m^2/min (0.1 US gal/ft^2/min) for vertical surfaces.

The picture on page 54 shows the areas the water spray system should cover.



In addition to the above fire protection systems the hull is protected by a water curtain that sprays water on the hull in the vicinity of the cargo manifold to protect the hull from cryogenic embrittlement.

5.10 Manifold and valves area

The ship manifold and valves area is one possible source of fire during loading/offloading operations.

Jetty monitors should be directed to this area but the ship dry powder and water spray systems would be used by ship's crew in the first instance.

The photographs above show the manifold area of the ship. The open grilles in front and below the manifold areas have trays designed to prevent the ship deck and hull coming into contact with any spillage. Water spray is maintained during cargo operations to vaporize any liquid spill and further protect the ship deck.

5.11 Atmosphere control

The operational procedures on an LNG carrier ensure that explosive mixtures do not develop in the cargo containment system. At no point is air in contact with LNG or natural gas vapour in the cargo tanks, cargo equipment or cargo pipework.

LNG carriers are equipped with inert gas and nitrogen generating plants. Older vessels may be equipped with bulk liquid nitrogen tanks instead of nitrogen generators.

Inert gas is used for purging when preparing ships tanks and pipelines for accepting natural gas after a repair period. The inert gas is used to displace the air from the ships tanks and cargo pipelines prior to the introduction of cargo vapour.

Conversely inert gas is used to displace cargo vapour from tanks and pipelines prior to the introduction of dry air in preparation for a repair period.

Inert gas is produced by burning diesel oil in a dedicated furnace in the ship's machinery space. The resultant exhaust gas is scrubbed, cooled and dried to produce an inert gas with a high nitrogen content, and a very low oxygen content and dew point. Dedicated inert gas blowers are provided to transfer the inert gas to the cargo tanks and pipelines.

Nitrogen is used to displace cargo vapour before opening any part of the cargo pipeline system, for example for the swinging of spectacle pieces or the change over of spool pieces. Nitrogen is also used to displace air, after any section of cargo pipeline has been opened up, prior to the introduction of cargo vapour or LNG.

Nitrogen is also introduced into the insulation between the primary and secondary barriers to ensure that an explosive atmosphere cannot develop in the inter-barrier space in the event of a leak from the primary barrier.

Nitrogen is used to purge air from the ship/shore manifold connection prior to the transfer of cargo and to purge cargo vapour from the ship/shore connection prior to disconnection.

5.12 Cargo transfer

LNG is loaded onto the LNG carrier via the liquid hard arms using submerged pumps in the shore storage tanks. The loading rate is increased slowly, in accordance with the loading plan agreed between the ship and the terminal prior to the start of transfer. The slow increase in loading rate avoids pressure surges in ship and shore pipe-work, and excessive vapour generation in the ship's tanks during the early stages of loading.

Vapour displaced by the LNG loaded into the ship's tanks is returned to the terminal via a separate vapour hard arm and pipeline. The return vapour may be free-flowed back to the shore tanks or assisted by a compressor on board the LNG carrier.

The loading rate is progressively reduced towards the end of the loading. The last tank is 'topped off' at a minimum flow rate. The ship's tanks are protected from overfilling by a high-high level alarm that will when activated automatically close the filling valve of the affected tank. The ship's tanks are also provided with an extreme high level alarm which when activated will initiate an ESD and automatically stop the cargo transfer operation.

LNG is transferred from the LNG carrier to the shore tanks at the discharge terminal, via the liquid hard arms, using submerged pumps in the ship's cargo tanks. As with the loading operation, the offloading rate is increased slowly in accordance with the agreed ship/shore unloading plan. The cargo vapour required to replace the unloaded LNG in the ship's cargo tanks is commonly supplied from the unloading terminal via a separate vapour hard-arm.

The return vapour may come directly from the shore tanks, and may be assisted by a return gas blower, or from down-stream of the boil-off gas compressors. In the later case provision is made to de-pressurize and cool the vapour before it is returned to the ship.

Where return vapour is not available at the unloading terminal it is possible for the LNG carrier to generate its own vapour using a high duty vaporizer. The unloading rate is progressively reduced towards the end of the operation and is normally completed using a single pump. It is common for an LNG carrier to retain a quantity of LNG, on completion of unloading, to keep the ship's tanks cold on route to the next loading port. This retained LNG is known as 'heel'.

5.13 Pre-arrival checks

Before an LNG carrier comes into a terminal or the terminal accepts an LNG carrier for transferring cargo, there are certain procedures, checks and meetings that must be done by both the LNG carrier and the terminal.

These pre-arrival and other checks are done to assure that all systems for the safe berthing of the vessel and transfer of the cargo are operating satisfactorily.

Examples of the checklists and pre-arrival checks required for both an LNG carrier and terminal are shown in appendices F, G and H.

Marine specific risk assessment

For marine related hazard and risk assessment of LNG spills over water the report compiled by Sandia Laboratories, Albuquerque, New Mexico, USA should be read in detail. This report was commissioned by the United States Coastguard and was issued in December 2004. The full title is: *Guidance on Risk Analysis and Safety Implications of a Large Liquefied Natural Gas (LNG) Spill Over Water.*

6 Passive fire protection

Industry standards and company specifications can be referenced for further information on the types and applications of Passive Fire Protection (PFP) suitable for the LNG industry. The following is an overview of PFP that focuses on LNG facilities protection.

The term Passive Fire Protection (PFP) refers to any protection measure such as fireproofing, fire resistant barriers or special coatings that do not require manual or automatic actuation for them to be effective in resisting the impact of fire incidents.

Within buildings, by regulations, there are always passive protection measures employed to prevent propagation of smoke, flame or heat by provision of such measures as fire doors, rate wall construction and ceiling void compartmentation. Such measures are appropriate to all buildings, not just those in the LNG industry.

However, the levels of protection required by statutory authorities for life safety are not usually sufficient for protection of critical facilities such as control rooms or critical switchgear facilities etc from the point of view of disruption to business continuity.

It is, therefore, not only important to review PFP measures in LNG processing, storage and distribution facilities but also LNG facility buildings. (This is particularly true for control buildings in or near to process equipment which might be subject to fire or explosion effects.)

6.1 PFP capabilities

Generally speaking, PFP is used to prevent or delay fire product (heat, flame, smoke or toxic fumes) spreading to critical structures, equipment or enclosures. Fire tests are used to rate PFP performance according to its ability to provide three key elements:

- Integrity—the ability to prevent the passage of smoke, flame or toxic gases.
- Stability—the ability to maintain its structure.
- Insulation—the ability to limit spot or area temperature on the 'non-fire' side of the PFP.

6.2 PFP ratings

Although different rating terminology systems are commonly used around the world, the most commonly used system to describe the properties of PFP is explained below.

A: Ambient

Face: This is a maximum temperature rise in Celsius on the area of the cold face in the time specified. Spot is simply a localized area on the cold face.

J (or JF) ratings refer to jet fires these are specific tests and they differ from that shown above.

Rating examples:

H60

- hydrocarbon;
- 120 minutes integrity/stability;
- 60 minutes temperature test limit.

HO

- hydrocarbon;
- 120 minutes integrity/stability;
- no insulation.

Manufacturers and research institutes are constantly developing new PFP materials and so it is important to ensure that the latest information on products including relevant detailed test data is available.

Rating terminology

Rating	Test Temperature Curve	Stability/ Integrity (Mins)	Temperature Limit °C(°F)	
			FACE	SPOT
B	Cellulosic	30	139 (282) + A	225 (437) + A
A	Cellulosic	60	139 (282) + A	180 (356) + A
H	Hydrocarbon	120	139 (282) + A	180 (356) + A

In the table above, A/B ratings refer to cellulosic material fires and are, therefore, relevant to most building applications.

'H' ratings refer to hydrocarbon spill fires. (Hydrocarbon fire tests simulate the more rapid temperature rise and higher end temperature that occurs with hydrocarbon fires compared to cellulosic fires.)

It should be remembered, however, that fire ratings are derived from standard tests and so it is important to ensure that the test is relevant to the application.

For most building applications this is relatively straightforward as the usual purpose is to allow safe exit and prevent passage of fire products until a professional fire response from, for example, the local authority fire brigade is available. As this is usually within minutes, the long-term performance of the PFP is often not an issue.

However in the case of LNG facilities, the PFP will usually be subject to the elements and may be required to perform over extended periods while a controlled burn-out of fuel occurs.

For LNG, it may also require cryogenic splash or cryogenic liquid immersion followed by a fire test, since this better reflects possible fire incidents at LNG handling facilities.

One particular type of fire where ratings achieved in standard tests can be a problem is the jet fire. In fact, because jet fires pose particular problems due to extremely high heat flux levels, their erosive effect and their ‘heat shock’ loading, all of which can vary considerably according to actual fire conditions, it has proved very difficult to get general acceptance of standard jet fire tests, although tests developed mainly by oil companies have now been published and are used for this purpose.

6.3 Cryogenic and fire testing of PFP

It must be remembered that PFP for an LNG facility may have to withstand initial cryogenic temperatures, followed by rapid high flame or radiant heat temperatures. For example, a liquid spill can result in −162°C (–260°F) from ambient, and then if ignition occurs, flame engulfment can raise temperatures to around 1000–1100°C (1,832 – 2,012°F).

The photograph shows a cementitious PFP sample being immersed in liquid nitrogen. After immersion, it requires some five minutes to remove the sample and prepare it for fire testing. This is as short a time frame as possible, given the nature of the testing requirement.

The 1-metre (3 ft) high steel column at the top right hand corner of the LNG pit in this photo has been coated with Chartek 7 passive fire protection. This intumescent based PFP has withstood repeated burns, water and foam applications as well as dry chemical applications during the BP LNG Fire School.

In this photo, the 1-metre (3 ft) high steel column coated with PFP in the fire area performed as specified in terms of fire protection. In the same photo, to the left of the fire area in front of the foam generator, can be seen another column with the same treatment. It is visibly burning, which is another feature of its performance in order to obtain charring for heat resistance. This burning should be noted by responders since if dry chemical is to be used to extinguish an LNG fire, there may be a source of re-ignition via this burning. Care should also be taken if using pressure sprays or jets for cooling where Chartek is used, as this may reduce the charring effect, although additional thickness may be applied to account for this effect, if necessary.

Any PFP being considered for an LNG facility where this may be the scenario should ensure that the PFP be tested against these conditions. Liquid nitrogen can be specified as a replacement for the LNG as the cryogenic liquid side of the test, followed by a hydrocarbon pool and/or jet fire test according to the fire scenario.

6.4 Typical applications of passive fire protection

Buildings

- Fire barriers or doors between enclosures.
- Protection of escape routes in buildings.

LNG facilities

- Protection of critical structural members in process areas.
- Protection of critical equipment (e.g. ESD valves and actuators).
- Protection of critical control cabling.
- Protection of process equipment.
- Protection of tanks.
- Protection of vessels and vessel supports.
- Containment pits.
- Run off channels.

6.5 Design considerations—all types of PFP

Standard test fires are available to assess PFP's performance in different fire situations (such as cellulosic fires, hydrocarbon spill fires). Fire ratings achieved during the tests are given by independent certifying authorities. However, as mentioned previously, the standard test fires do not necessarily represent the exact conditions that will be encountered on an installation. It is therefore vital that the selection of PFP is based on test data relevant to the actual requirements.

To be effective, PFP must provide total integrity. It is absolutely essential that any gaps in or penetrations through the protection such as those caused by doorways, pipes or cables are filled with compatible materials or transit pieces having the same fire performance capability.

The performance of the PFP material alone should not be the only consideration but rather the performance of the total system including bonding methods, retention systems, top coats, installation techniques and installer capability as a total package.

The following is a brief description of the more commonly used specialist materials for PFP. In some cases, manufacturers offer products based on the potential advantages and disadvantages of each type, it should be recognized that properties and physical characteristics within the same generic type can vary considerably from one manufacturer to another and developments and improvements are taking place continuously.

6.6 Intumescent materials

Normally epoxy based, these materials swell and convert into carbon when exposed to fire. The carbon based char then forms a low conductivity thermal barrier. In some cases subliming materials which absorb energy in turning from solid to vapour may be included in the product. Intumescent materials are most often used as spray coatings but are also available as paints and varnishes, prefabricated panels, mastics for general sealing purposes and in strip form for sealing gaps such as those between doors and door frames.

Potential advantages

- Epoxy based spray intumescents can be used for all configurations of steel work. They can exhibit superior physical and mechanical properties leading to a longer life span and lower repair requirements than other spray materials.
- They are normally extremely weather resistant and less prone to water or oil absorption than other types (although some types may require a top coat).
- They can provide good corrosion protection to the substrate.

Potential disadvantages

- Intumescents can combust initially and burn as they char. Thus, if dry powder is used to extinguish an LNG fire, intumescent PFP can act as a re-ignition source.
- Intumescents may give off toxic smoke and fumes as they char.
- Erosion of the char can be caused by jet fire impingement.
- Erosion and degradation can occur by use of water streams for cooling under fire conditions.

Special considerations

- Normally spray applied intumescent materials require a retention system. Although the epoxy base material itself is inherently water resistant, the intumescent materials may not be. Consequently, weatherproof top coats may be required.
- Mixing of components in the correct proportion is critical to performance. Considerable safety procedures are often required during application and curing.

6.7 Cementitious materials

Cementitious coatings have been tested at the fire school on sample I beams and have been noted to stand up well to the repeated fires of the school. While such coatings are obviously more heavy than intumescents, they do not have the potential for combustion and ignition of gas.

Cementitious PFP materials use a binder with a hydraulic set when mixed with water and a filler with good installation properties.

Normally the binder is Portland cement although magnesium oxychloride, magnesium oxysulphate and gypsum have been used. Fillers may be vermiculite, mica, mineral fibres or ceramic fibres. They are usually spray or trowel applied but may also be cast to preformed shapes or sections.

PFP performance relies on a combination of two effects—insulation and dehydration causing cooling.

Potential advantages

- Cementitious PFP can be applied to all configurations of steelworks although sharp radii items may cause problems.
- Water pick-up post-fire can re-establish some capability (but structural strength will be affected).
- Cementitious materials do not normally emit toxic fumes in fire situations (although topcoats might).

Potential disadvantages

- Oxychloride and oxysulphate cements can cause corrosion to the steelwork to which they are attached. Portland cement based cementitious coatings do not normally directly cause corrosion, but may accelerate the process by virtue of water retention unless the substrate is protected.
- Inspection of the substrate can be difficult.
- The coatings are porous and should be protected with a topcoat system which must be carefully maintained over the life cycle of the product.
- The topcoat integrity needs to withstand water streams for cooling to minimize degradation.
- The impact resistance of cementitious coatings tend to be lower than that of the epoxy-based materials.

Special considerations

- Spray applied cementitious materials normally require retention system.

6.8 Ceramic and mineral wool fibres

These are inherently insulating fibrous material bound together either by weaving or with a chemical binder. (Ceramic fibres tend to have a higher melting point than mineral wool fibres and so can achieve higher fire performance ratings.)

The materials can be used either as flexible blankets or as a steel or composite material panels.

Potential advantages

- The flexible nature of these materials allows them to be used for relatively complex shaped items.

- Compared to spray coatings they can be more easily removed for inspection of the protected equipment although great care must be taken to replace them correctly.
- Fire blankets normally provide a relatively lightweight protection method.

Potential disadvantages

- The binders used with the fibres may decompose in a fire situation and release toxic fumes.
- Blankets should be protected against ingress of water which could lead to corrosion of the protected equipment. It is normal practice to provide a barrier—often an aluminium foil—to prevent water ingress and formation of condensation on the substrate.
- The lower melting point of mineral wool means that it is not normally suitable for PFP application in hydrocarbon fires.

Special considerations

- Fibres may settle within a barrier with vibration thus reducing effectiveness in some areas.
- Restrictions on fibre particle size may have to be imposed due to potential health hazards.

6.9 Foamglass blocks for radiant heat reduction

The October 2006 fire school has highlighted that use of a type of foamglass block, in groups of 100 small 'bricks', held together by fire resistant cover material can contribute to fire size reduction and therefore radiant heat reduction. This

Foam glass blocks within their fire resistant covers. *Picture courtesy Pittsburgh Corning*

Foam glass blocks within an LNG pit. The blocks should be rested on a grid above the pit base, to allow water drainage. *Picture courtesy Pittsburgh Corning*

Foam glass blocks floating on LNG in the pit. Whilst vaporization is not reduced, fire size is reduced to make fire extinguishments with dry chemical easier. *Picture courtesy Pittsburgh Corning.*

heat reduction offered benefits to the fire responders in that they could advance closer to the fire than previously possible, unless using high-expansion foam.

Whilst these foamglass blocks are not yet considered as an alternative to high-expansion foam for fire reduction in containment pits and run off channels, there is obviously potential for heat reduction as an aid to emergency response and control of contained LNG fires. However, this would have to be subject to further testing.

It should be noted that the blocks did not appear to significantly reduce vaporization and their strength is therefore in their ability to reduce fire size and radiant heat. The manufacturer of the blocks is Pittsburgh Corning Corporation-International and the blocks are their Foamglass Insulation Product.

7

LNG, gas and fire detection

An accidental release of flammable gas at an LNG facility must be detected as rapidly as possible to avoid the possibility of either a flash fire, a confined or partially confined vapour cloud explosion and a possible residual pool fire.

Fire and gas detection has also become very important at facilities and terminals where minimum numbers of operators are employed and human presence is reduced.

7.1 Cryogenics liquid detection

Whilst gas detection can alert operators to LNG vapours, an earlier method of detecting cryogenic liquids is to provide thermocouples or fibre optics that will alarm once the LNG makes contact. Containment pits are obvious locations for such detection, but drainage channels should also be considered, for earliest alert to a release.

7.2 Gas detection

Catalytic gas detection

The conventional point catalytic detector typically consists of an electrically heated platinum wire coil covered with a ceramic base (for example, alumina), and a palladium or rhodium catalyst. This sensing element—the 'pellistor bead' —responds to an influx of gas into the detector housing by heating up and altering the resistance of the platinum coil. The degree of heating is proportional to the amount of combustible gas present and can be displayed on a meter.

Poisoning of this type of detector can be caused by substances such as silicon-based greases, and, in some cases, excessively high background gas concentrations outside the upper explosive limit.

Other problems with catalytic detectors include the blockage of the sintered disc with particulates such as oils, fine dust, salt, grit, corrosion or even water.

As they are of a 'point' type, (one detector in one spot) catalytic detectors need to be located near to potential points of gas release and must also take account of gas densities. It may therefore be necessary to mount point catalytic detectors at higher than normal levels to ensure they detect a methane-based gas release.

Catalytic detectors are not considered best practice for LNG facilities given the availability and reliability of infra-red gas detection technology.

Infra-red sensor gas detection

This type of detector overcomes the problems of catalytic types and can be used at jetties, berths and terminal facilities as well as process facilities.

Advances in Infra-Red (IR) technology have resulted in both point and 'open-path' type detection, also known as 'line-of-sight'. For both point and open-path devices, IR detectors utilize the fact that gases absorb infra-red energy at certain wavelengths.

Point IR gas detection

The point IR device is a sealed detection tube containing both IR transmitter and receiver. In this case, the output (i.e. gas present) is proportional to the amount of IR absorbed by the gas.

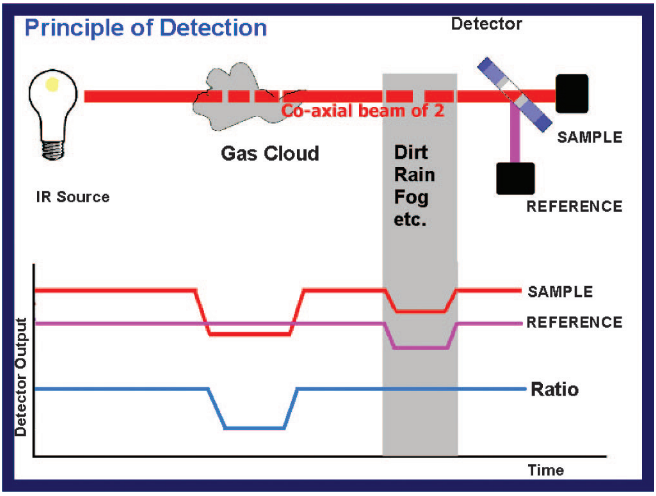
Photograph example of a point IR detector. *Photo courtesy Resource Protection International.*

Open path IR detection

The open path IR gas detector principles can be likened to a conventional optical beam smoke detector in appearance and configuration, but will measure the attenuation of IR by a gas cloud between a transmitter and receiver over a large area. Dirt, rain or fog will have the same impact on the signals, but where gas absorbs the 'sample' wavelength, an alarm and reading is given.

Open path detectors can 'scan' a large distance, or 'path length'. Typical coverage distances may be in the order of up to 300 metres (985 ft), although in practice these may be limited to <100 metres (<328 ft) to ensure accuracy and reduce spurious alarms.

Open path IR detectors make a second reading at a reference wavelength, not absorbed by hydrocarbons, so that differences in signal-to-noise ratio can be interpreted as environmental effects.



Graphic courtesy Resource Protection International.

In effect, the beam measures the 'total' amount of gas present along the beam, as if a row of point detectors were placed end to end. In this way, the 'significance' of a gas release hazard can be estimated. This feature enables open-path detectors to be used effectively as perimeter monitoring devices to track the size and direction of releases, especially where identified ignition sources are nearby to potential release areas or where facilities are adjacent to public roads or public areas.

Further information on open path gas detection readings and data during the BP LNG Fire School tests is included in Appendix A, particularly the outcomes of tests conducted with the open path detection.

Example of an Open Path Gas Detector (OPGD) in place at the BP LNG Fire Ground at the Texas A & M university. This particular type of OPGD proved to be robust, reliable and free from spurious alarms over the duration of the BP LNG Fire Schools during 2004 and 2005. *Picture courtesy Detect and Measure.*

The optimum configuration of detectors will depend mainly on manufacturer's guidance. The following recommendations and observations should be noted:

- Detectors should be set such that sufficient warning is given of a release. A typical detector may be set to alarm at 20% LEL.
- IR point detection may be supplemented by open path detection configured such that it offers 'perimeter monitoring' around an LNG storage area or other LNG area. The best configurations may include both types of detector so that emission points can be pinpointed or 'tracked' by point detection, whilst the open path component gives an indication of average concentration over an area, thus estimating the potential for a 'significant gas' hazard.
- Specific design guidance relating to individual components and capabilities can be found by consultation, whilst more general guidance may be found in the following documents:
    - BS EN 50054:1999: Electrical apparatus for the detection and measurement of combustible gases—general requirements and test methods.
    - BS 6959:1989: Selection, installation, use and maintenance of apparatus for the detection and measurement of combustible gases (other than for mining applications or explosives processing and manufacture).

Company specific gas detection guidance documents should also be checked for further reference.

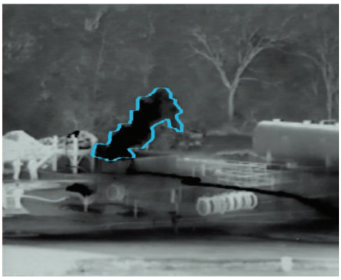
Hydrocarbon gas imaging

This is a new technology which has aided test work at the BP LNG Fire School. Using this imaging technology, it is possible to actually 'see' a gas cloud in real time. It is also possible to compare the gas cloud to the condensate cloud surrounding the gas cloud.

To give an example, during one test on an extremely humid day, the condensate cloud was not only three to four times the size of the methane cloud, but also started to act as an insulator in stagnant wind conditions. The imagery provided information which was not hitherto available.

Work is ongoing to quantify actual vapour reduction, using the open path and point IR in combination with this gas imaging technology.

Vapour cloud before foam application. *Picture courtesy Flameout*.



Vapour cloud after foam application. *Picture courtesy Flameout.*

This technology may have future specialist applications for the LNG and the oil and gas industry in general but as yet there are no standards or guidance to apply such technology.

Most leaks can be visually detected from ground level or at one or two metres height. Gas imaging may be carried out up to 50 metres (164 ft) from the target area.

The gas imaging technology shown above is now being becoming available from companies including Leak Survey Inc (GasFindIR camera) and Heath Consultants (remote methane leak detector).

7.3 Fire detection

Fire detection can be broadly categorized as either smoke, heat or flame detection. The type of detector selected will need to take into account the expected nature of combustion 'products' given off by any fire. These may include smoke, heat, visible flame and incipient fire gases such as CO.

Smoke detection

Smoke detectors are widely used to detect smouldering or flaming fires capable of generating quantities of smoke as a consequence of combustion and may be 'point' type or 'volumetric'. Point detectors may be of the 'ionization' or optical ('photo-electric') type. Volumetric smoke detectors may include 'beam' type detectors or 'incipient' units.

(a) Ionization smoke detector

The ionization smoke detector utilizes the phenomenon that ions are attracted to smoke particles. A small sampling chamber containing air is ionized by a weak radioactive source. When combustion products enter the chamber the particle charge pattern is modified and the air conductivity is reduced, producing a change in the ionization current flowing between two electrodes. In this way, a change in potential difference can be measured and an alarm can be generated.

(b) Optical smoke detector

Smoke particles entering the detection chamber affect the propagation of a beam of light, either by obscuring its intensity or by scattering of the beam path.

These effects are used to detect smoke using photoelectric detectors consisting of a directional light beam and a photosensitive receiver.

(c) Beam detector

Beam or 'linear smoke detectors' consist of a light transmitter emitting an invisible infra-red beam, which is picked up by a receiver up to 100 metres (330 ft) away. If smoke passes through the beam the infra-red radiation is weakened. If the signal received falls below a set value the receiver circuit initiates an alarm signal. Slow changes to the signal as a result of dust accumulation or other environmental influences, as well as blockages to the beam are offset by a compensating circuit.

(d) Incipient fire detection

Incipient smoke detection, or 'aspirating' detection has developed as an effective way of providing protection in 'clean room' environments such as computer suites or control rooms containing sensitive electronic equipment. This type of detection relies on sampling air within the protected space via an array of detection pipework, which is then drawn back to a central or local detection unit for analysis. A typical unit can detect smoke concentrations as low as 0.01% obscuration per metre (0.003% per ft) and will contain algorithms able to distinguish between smoke particles and other possible causes of false alarm such as dust or fines in the air ('particle rejection'). This type of system will be able to 'buy time' and allow an initial investigation at a set pre-alarm level to be made. Action to respond to the fire may then be taken either manually, or via means of some other 'executive' action.

An incipient smoke detection system. This particular type of system has been successful in detecting two real time incidents at a BP LNG control room. *Photograph courtesy Air Sense Technology*.

Incipient smoke detection systems should be the preferred smoke detection system for control rooms, IT rooms, electrical switchgear rooms etc.

7.4 Recent incident experience

Two recent instances of where such incipient detection systems responded as designed were as follows:

- In Spain at an LNG import facility, the system detected and alarmed an overheating cable that had not ignited.
- Also in Spain, an overheated electrical switch was detected and alarmed which, when visually discovered, was beginning to melt inside.

Both these incidents involved control rooms and highlight the efficiency of an incipient smoke detection system.

7.5 Heat detection

Heat detectors respond to an increase in temperature associated with developing fires. Such detectors may be of the point 'fixed temperature', 'rate-of-rise' or 'rate-compensated' type. A further type of 'linear' heat detection (LHD) comprising a cable or tube, which can detect hot spots at any point along their length, is also useful for specific applications.

7.6 Flame detection

Flame detectors convert electromagnetic radiation emanating from flames into an electrical signal, which is then processed for alarm actuation. They may be used where flames are the indicator of fire (as opposed to smoke).

Such detectors may be optimized to sense infra-red (IR), ultra-violet (UV) or a combination of both (UV/IR) portions of the flame emission spectrum.

Flame detectors are 'cone of vision' devices and need to 'look' at the expected source of flame in order to be effective. They are able to distinguish between flames and other sources of radiant energy on the basis of the wavelength of the received radiation.

UV flame detectors

UV detectors are sensitive to most fires, including hydrocarbon (liquids, gases and solids), metals, sulphur, hydrogen and ammonia. However, the presence of large quantities of smoke, contaminants and UV absorbing gases or vapours in the detection area may attenuate radiant energy, decreasing detection efficiency.

For this reason, the area must be surveyed carefully to ensure that these effects are reduced.

IR flame detectors

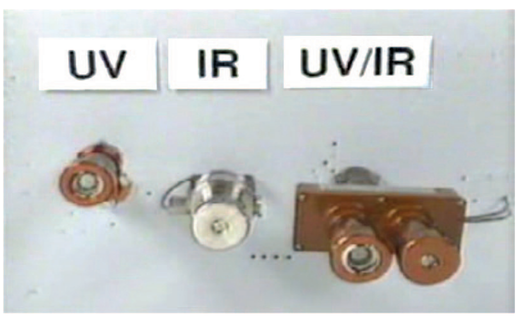
Most IR sensors are broadband detectors responding to a wide range of wavelengths and require optical filters to narrow the response to wavelengths of interest.

A common type utilizes the 4.4 micron wavelength, chosen to detect the emission of carbon dioxide, which is given off by burning carbonaceous material. A high intensity of spurious 4.2 to 4.5 micron radiation is absorbed by the earth's atmosphere and so a high intensity of 4.2 to 4.5 micron radiation results at ground level from hot body or carbonaceous fires. Discrimination between hot body and fires is usually achieved by monitoring the characteristic flame flicker frequency. A disadvantage of some IR detectors is that fires not containing carbon (such as hydrogen fires) will not be detected, necessitating careful survey and selection.

The latest generation of IR devices (IR-3 generation) are able to detect three separate wavelengths present in the IR spectrum of a burning fuel. This may enable the detector to 'see' previously unseen fuel types and may represent a cost-effective alternative to the provision of separate IR and UV devices or other combined units.

UV/IR flame detectors

These consist of UV and IR sensors within one unit. The two sensors operate independently as described above, and an alarm is usually generated when both sensors detect a fire. Current UV/IR sensor technology provides a very sensitive and stable detector, although the limitations are often a combination of both UV and IR detectors regarding source absorption.



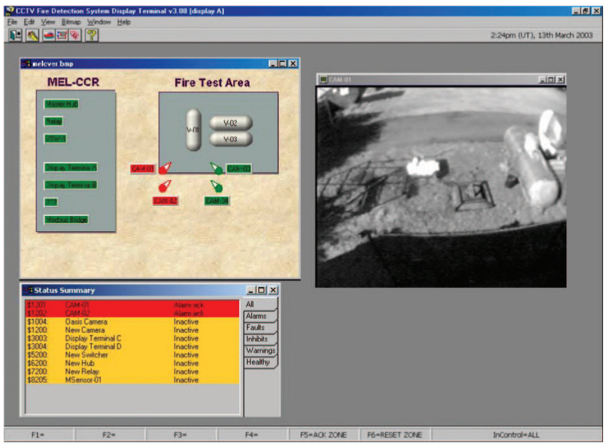
Examples of UV, IR and combined UV/IR flame detectors.

Optical (flame imaging) detection systems

Until recently, the causes of unwanted alarms from optical flame detectors have been poorly understood. A common cause of false alarms with optical detection systems has been nearby flare stacks, since detectors can respond to reflections in water or on metal surfaces. This problem has been overcome in some instances by the application of 'flame imaging technology', which typically incorporates three basic components—the camera/detector, control panel and visual display.

The camera/detection unit contains the camera and computing facilities to determine whether or not the unit is 'seeing' a fire, and is programmed with a range of algorithms to determine whether the phenomena within its field of view are fires or not.

If a fire is detected, the view of the camera is automatically displayed at the control point. Sites using this type of device are reporting that one of the main benefits is being able to see a ‘live’ image of the area of alarm, providing unambiguous information about the detection



In the example of flame imaging detection above, the CCTV cameras have picked up jet fire on the test vessel and appear on the computer VDU in red colour with alarm. The flame imaging detection has been tried and tested at the BP LNG Workshop in Texas and has proved effective and reliable for LNG fires. (*Picture courtesy Micropack.*)

Flame imaging is the preferred flame detection for LNG handling facilities and plant. Utilizing data from three years of tests, the algorithms of the flame imaging system have been remodelled to increase accuracy and speed of detection.

This type of flame imaging detector has been used extensively at the BP LNG Fire School without failure or spurious alarms. This detector interfaces with the software in the photograph above. (*Picture courtesy Micropack.*)

Another view of the camera detector seen in the photo on page 74. The main advantage with this type of detector and related equipment is the almost elimination of spurious alarms that are found with most conventional flame detectors. (*Picture courtesy Micropack.*)

Fire detection executive actions

Whilst a fire detection system will provide early warning of a fire condition, unless it is linked to an appropriate active fire protection system or a suitable response can be provided, the detection itself will not perform any mitigation function.

Heat detectors are not generally suitable for the protection of life since their response is much slower than smoke detection.

Their use should be restricted to defined areas where smoke detection is problematic or alternative detection cannot be used.

Where the possibility of high pressure gas fires exists, the use of UV/IR flame detectors may not be appropriate, since these types of fire exhibit little or no low frequency flickering, which may be required by the IR sensor.

General design guidance

In all cases, detection systems should be designed taking into account all relevant factors relating to the Fire and Explosion Hazard Management (FEHM) strategy for the facility. The most comprehensive family of standards relating to fire detection of all types is EN-54, parts of which are currently in draft form. In the absence of a current EN-54 document, the corresponding part of BS5839 (British Standard) should be referred to. General design guidance is contained within BS5839 Part 1: Code of Practice for the Design, Installation and Maintenance of Automatic Fire Detection Systems. In the US, or for guidance not contained in the European family of standards, NFPA 72 may be applicable.

8

Spill and fire control measures

The volatility of LNG liquid is such that when spills occur in depth or liquid spillage is diverted to containment or impounding pits, the vapours cannot be completely suppressed as is possible with most, though not all, flammable liquids.

The recommended methods for dealing with unignited and contained LNG spillage include:

- high expansion foam;
- water curtains.

High expansion foam reduces vaporization and thereby vapour cloud size and migration, but it cannot completely prevent vaporization.

Note that it may often be preferred not to extinguish LNG fires (by using dry chemical) as the evolving gas is burnt off in a controlled way until the incident can be declared over. There are exceptions to this, including jetty loading manifolds if the LNG cannot be drained away.

Premature extinguishment can create invisible vapours, which if caught in a confined space with ignition potential could cause an explosion.

After initial radiant heat reduction, the residual LNG should be burnt off through the foam blanket under controlled conditions with regular foam top up.

The recommended methods of dealing with burning LNG include:

- dry chemical, which can extinguish an LNG fire;
- foam, which can reduce fire size and radiant heat intensity but which cannot extinguish the LNG fire;
- water curtains, which can also be used to reduce radiant heat impact on adjacent or nearby structures and plant.

These methods are further explained below.

8.1 Foam for LNG vaporization reduction

The use of good quality firefighting foams at high expansion ratios (typically 500:1) will reduce LNG impounding and containment or retention pit spill vaporization.

Previously, the evidence for this vapour reduction was limited and whilst the industry recognized this reduction, the quantification of the reduction was not a simple affair.

However, the 2004 and 2005 tests at the BP LNG Fire School have clearly demonstrated and quantified reduction by showing up to 60% vapour reduction (see Appendix A). This obviously reduces the distance to LFL of the vapour cloud.

It is also now clear that unaspirated foams and low expansion foams do not significantly reduce LNG spill vaporization.

This is due to their high water content whereby the water drains off rapidly to increase the LNG vaporization and therefore these foams do not contribute to significant vapour reduction and should not be used.

To assist project engineers develop effective specifications, extensive test work has been carried out at the Emergency Services Training Institute of the Texas A&M University System, as part of the BP LNG Live Fire Training Workshop.

While previously only historical data with national standards and codes would have been available as the only reference point for this important work, the BP LNG Fire School, held at the Texas A&M University Fire Ground has enabled modern solutions to be developed through realistic scenario testing.

These tests have given validation to those national codes and standards but they have also raised a number of anomalies, for which solutions have been found.

The BP sponsored LNG Fireground at Texas A&M was constructed partly to carry out medium and long term testing of foam concentrate and foam making equipment under realistically onerous conditions.

It was also developed to determine the precise parametres that will ensure maximum effectiveness and efficiency in both fire control and vapour dispersion of LNG for implementation in new build and upgrade of existing facilities.

A set of three containment pits have been constructed and used for vapour and fire control as follows:

- 10 $m^2 \times 1.2$ m depth (108 sqft $\times$ 4 ft)
- 65 $m^2 \times 1.2$ m depth (700 sqft $\times$ 4 ft)
- 45 $m^2 \times 2.4$ m depth (484 sqft $\times$ 8 ft)

These were built to replicate modern operational LNG containment facilities.

In addition, a 16 m $\times$ 1.2 m deep 'L' shaped pipe trench was built, 1.2 m wide (52 $\times$ 4 ft deep $\times$ 4 ft wide) (19.2 m^2 (206 sq ft)) to simulate realistic drainage trench conditions. An internal raised pipe ledge was provided with simulated LNG and water pipes (filled with water to prevent buckling).

Historical foam application data

Considerable vapour and fire control testing on LNG has been done in the past. However, much of this was in sand or earth pits and often wetted with sloping sides in order to determine minimum foam application rates, which often gave very slow control times, even under ideal test conditions.

These previous typical test conditions did not represent an effective basis for operational conditions, where the commonly used modern containment pit design standard has vertical sides of reinforced concrete.

Some historical test work has used low test application rates (typically below 5 litres/min/m^2 (0.12 US gal/ft^2/min)) but these have generally been conducted in ideal weather conditions with wet sand or earthen pits, usually moistened so the side walls are also iced down to −164° C (–263°F) as the LNG arrives.

These types of pits do not generate the much higher radiant heat levels of reinforced concrete pits installed on the BP LNG Texas A&M fire ground. Nor are these types of pits to be found on most operational LNG sites.

Also, they do not take account of rain storms, wind effects or any peripheral deluge water from exposure protections that may inadvertently drain into the LNG pool, which makes for a significantly more challenging problem to control.

Such practicalities require considerably higher application rates for operational use than during tests, a factor beginning to be acknowledged by recent editions of system design standards.

Unlike most fire applications, there have as yet been no major LNG incidents to prove the inadequacy of low application rates on LNG.

Current position (2006)

Current test work on foams at the BP LNG Fire School confirms the historical findings that high expansion foam is the most effective answer for LNG protection and 500:1 expansion ratios represent the best all round answer for LNG applications.

Lower expansion ratios risk boiling the LNG too vigorously. The ratio of 500:1 provides the right compromise of water input for effective reduction of vaporization rate on an unignited LNG spill, while gently warming the escaping methane vapours so they rise away from ignition sources.

A 500:1 ratio also provides sufficient stability and cooling for an LNG fire to achieve 90% reduction of the intense radiant heat should the LNG pool catch fire before the foam system is activated.

Acceptable foam application rate

Internationally accepted guidelines like NFPA 11A & NFPA 59A currently avoid making any definite recommendations on this subject, referring users to defining application rates by test. (See annex H of NFPA 11.)

Individual foam generators and foam concentrates will vary in their uniformity of bubble production and ability to withstand the rigors of this particularly severe application, so actual LNG fire test data should be provided for any unit prior to purchase.

If there is no foam application rate stated in a specification or just a low historical rate (around 3–5 litres/min/m^2 (0.08 to 0.12 US gal/ft^2/min)) where much longer control times (in the order of 150–300 seconds) were achieved, this should be considered unacceptable.

While a time lapse of 2–5 minutes before control of an LNG pit fire may at first glance seem acceptable, the overriding objective of installing a foam system for fire or vapour control is to achieve the fastest possible fire reduction or vapour cloud distance to LFL reduction.

Given the extremely high level of radiant heat from an LNG pit fire, it is vital that the shortest possible time for control is achieved. Therefore every minute and, in some situations where heat exposures are nearby, every second becomes important for fire control.

The test work at BP LNG Fire School at Texas A&M shows that only the relatively high rate of 10 litres/min/m^2 (0.25 US gal/ft^2/min) foam solution flow achieves the required fast levels of fire control, which has consistently been shown to be effective.

This rate is to be used for LNG containment/retention pits where they are adjacent or close to manned areas, plant or jetty ship manifold areas.

Recognizing that plant design may allow for greater spacing where land permits, for small impoundment pits which can be located well away from plant or personnel, a reduced rate of 7 litres/min/m^2 (0.17 US gal/ft^2/min) may be appropriate, but only if this concurs with the site risk assessment.

It is further recognized that since higher foam application rates and expansion rates are in use, the foam system costs will be more.

However, higher rates are much quicker to control (either in vapour or fire phases), and they also require less frequent ‘top-ups’ during LNG presence. This is due to less heat production and therefore less foam used.

Also, whilst a higher pumping capacity is needed, less foam concentrate is required to be held in the system to cover the overall incident.

On the basis of reputation alone, the earliest response to and effective reduction of any fire at a facility will more than return the initial costs of effective high expansion application rate systems. Overall, once a foam system is installed, the maintenance requirements are the same.

It is therefore recommended that a specific foam solution application rate of 10 litres/min/m^2 (0.25 US gal/ft^2/min) capable of a reduction in radiated heat of 90% within 60 seconds and minimum depth of foam as 1.2 m (4 ft) is stated as a minimum requirement for all future high expansion foam systems, using a nominal expansion ratio of 500:1 (with a tolerance level of +/−50:1) in LNG facilities.

This standard requirement should ensure that all LNG sites are providing the most appropriate, fully tested and proven and therefore the most effective fire suppression for their identified contained LNG fire scenarios.

Lesser requirements can lead to an inferior system that will not provide the level of protection that has been proved effective, possible and practical to achieve. This will avoid potential failures through delays under emergency conditions.

Equipment used continuously and without failures during the test work included:

- Angus Fire LNG Turbex high expansion foam generator skids and hoods;
- Angus Fire Expandol high expansion foam concentrate.

Other similar equipment that has been tried and tested in real time scenarios at the BP LNG fireground would be acceptable provided the same level of active vapour and fire control is achieved without failures (reliability) in order to meet BP's stringent requirements.

Foam control maintenance (foam application cycling)

Once applied for either vapour control or fire control, foam has to be re-applied to ensure either the vapour or radiant heat is kept to acceptable limits.

The test work at the BP LNG Fire School shows that once 90% radiation reduction is achieved, regular foam top ups will be required and foam stocks should be planned on requiring 30 seconds foam usage for every minute the LNG continues burning.

Assuming a conservative LNG burn off rate of 12 mm (0.5″) per minute, the anticipated maximum depth of the LNG in a containment pit can be used to predict total concentrate requirement. In every instance, the worst-case scenario from the risk assessment should be used.

The outcome of the calculation, in terms of foam concentrate to be held in the system, should also have a 100% reserve on site in case of overrun due to other factors including heavy rain at time of incident, high winds or other unforeseen events on site. In this way, sites should not exhaust their foam concentrate before the LNG incident is over.

This same foam application cycling rate should be considered for vapour (unignited) top up, since systems are not designed for either vapour or fire control, but for both and therefore fire effects on foam blankets are taken as the worst case requirement.

LNG trench foam application

Foam application for LNG trenches presents a different and more difficult application requirement, which is likely to need a lower expansion ratio to allow the foam to flow along the trench following the LNG. Foam application equipment and application rate requirements are still under development at the BP LNG Fire School.

Work is ongoing to make formal approaches to the various international foam standards committees to have both LNG application rates raised and the time to achieve fire control reduced respectively.

Appendix A contains details of the foam system testing outcomes at the BP LNG Fire School and also contains the supporting information for the foam requirements in this section.

High expansion foam

High expansion foam systems are recommended for the following:

- LNG storage tank dikes/bunded areas;
- sumps;
- transfer lines;
- pump areas;
- jetties;
- liquefaction and vaporizer heat exchanger areas;
- LNG truck loading and unloading areas.

For contained LNG spills or fires, portable high expansion foam units should not be considered due to the need to approach extremely closely to attempt foam application from high expansion foam portable generators.

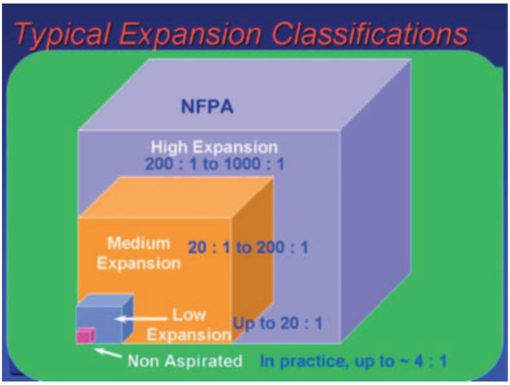
Medium expansion foam

Medium expansion foam offers some LNG spill vaporization reduction and some fire reduction capability, but this requires much higher application rates and is not as effective a response measure as high expansion foam which creates better and faster radiation reductions. Medium expansion foam application should be viewed as a mobile/portable response measure for drain trenches/channels where fixed systems do not exist.

The stream range from medium expansion foam branches/nozzles offers some ‘stand-off’ application capability, but is unlikely to be adequate for containment pits, unless less than 20 m^2 (215 sq ft) area.

Therefore, medium expansion foam should not be the first choice for LNG vapour or fire control strategy. If considered for a mobile/portable response, the medium expansion range should be in the order of 150–200 and should also use a high performance foam concentrate, preferably an AR-AFFF type concentrate.

Live tests should be conducted with the high performance foam concentrate before adopting such a portable strategy. Recent testing at the BP LNG Fire School has shown that a 3-3 grade AR-AFFF, when used at a 6% proportioning rate and as a medium expansion foam, can reduce LNG vaporization, though clearly not as effectively as high expansion foam.



The chart shows the types of foam available for the industry. Only high expansion foam is truly effective on LNG liquid and offers the best control.

There should be no ignition sources in the areas where vapour migration from the pit may occur. Obviously, vehicles and personnel should remain outside the hazard area. Therefore, at the design stage, whilst foam systems should be considered, especially for common bunds containing more than one tank, their need should be subject to thermal radiation assessments impact on adjacent or nearby facilities and equipment.

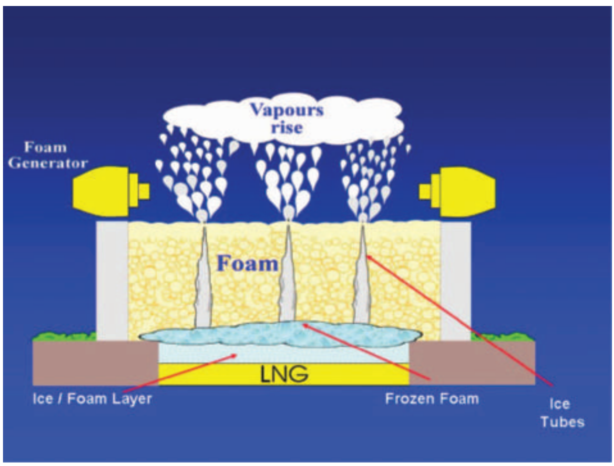
Example of high-expansion foam pourer system into LNG tank bund. (*Photo courtesy Angus Fire.*)

8.2 LNG vapour reduction

When foam is applied to LNG liquid it initially adds heat which increases the vaporization rate. However once this initial vapour surge is dispersed, the foam significantly reduces the vaporization rate and warms the LNG vapour to the point where it becomes positively buoyant. The LNG vapour therefore disperses as a rising plume, rather than moving along the ground. Consequently, the hazardous vapour dispersion zone may be substantially reduced by the application of high expansion foam.

Where foam systems are provided, the application of foam on an LNG spill will lead to icing over some of the LNG liquid surface with the formation of 'ice tubes' through which vaporization continues.

Foam does not appear to completely 'seal' vapours at the edge of an impounding/containment pit, although a top sloping wall appears to offer the best opportunity to limit vaporization at the pit edges, rather than a fully vertical containment pit.



The water content in the produced foam forms an ice layer on top of the LNG and the foam above this freezes to a few centimetres depth. The LNG vapours tend to then create 'ice tubes' up to the surface of the foam/LNG area with the vapour releasing above the top of the non-freezing foam layer. (*Diagram courtesy Angus Fire.*)

Example of high expansion foam discharge into an LNG containment pit. It is necessary for the foam to build up and flow over the pit top to achieve best vapour reduction results. Vertical wall pits do not appear to be as effective in allowing the foam to seal the vapours as a top sloping pit. Hoods to direct the foam into the pit and minimize the impact of wind are also recommended. (*Picture courtesy of Angus Fire.*)

High expansion foam discharge onto an LNG spill in a containment pit. The vaporization rate and gas cloud migration was markedly reduced using the high expansion foam. Some vapour can be seen at the high expansion generators in the mid-picture, but the surface area vaporization is clearly reduced. (*Picture courtesy Resource Protection International.*)

Example of large capacity high-expansion foam generators. It is necessary to ensure that the generators, which will be in a potential fire area and subject to flame impingement can withstand the fire temperatures involved. Conventional steel and other alloys will not normally be adequate for foam application under fire conditions. (*Picture courtesy Angus Fire.*)

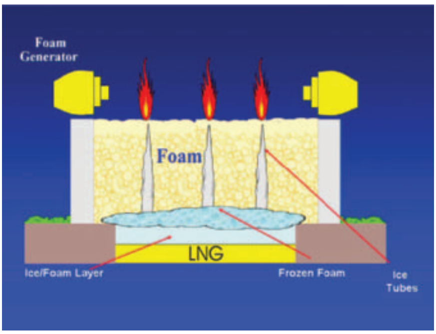
As with any foam application, once a foam blanket has been applied, it will need refreshing 'top-ups' in the form of re-application to ensure ongoing vapour suppression. Applied foam gradually degrades with the water in the foam bubbles draining out. Although a foam blanket may seem intact, with the water drained, there is little resistance to vapours.

8.3 LNG fire control and radiation reduction

As with vapour reduction, use of quality firefighting foams in certain expansion ratios can also reduce contained LNG fire radiant heat and the flame size of such a fire. As with the unignited spill foam application, the foam has to be aerated. NFPA 11 and BS 5306 both recommend high expansion foam systems for the protection of LNG hazard areas.

For new facilities, only fixed high expansion foam systems should be considered for LNG containment pits. Previous concepts that it may be possible to utilize a mobile and portable deployment of foam application units are extremely hazardous in practice; whilst a mobile response for LNG spills outside of contained areas may be considered in some circumstances. For containment pits, only fixed high expansion systems shall be used.

The same principles of icing and ice tube formation apply to foam application on LNG contained spill fires as well as the unignited spill (ice tubes may not reach the warmer foam surface). The difference is that foam will not extinguish the LNG fire and therefore the ice tube 'outlets' will continue to burn as shown below.



Once the LNG is burning, foam application will not extinguish the fire but the water content in the produced foam forms an ice layer on top of the LNG and the foam above this freezes over to a few centimetres depth. The LNG vapours tend to then create 'ice tubes' towards the surface of the foam/LNG area with the LNG continuing to burn from vapour releasing above the top of the non-freezing foam layer. (*Diagram courtesy Angus Fire.*)

LNG burning freely in a retention pit, prior to high expansion foam application. Flame height and radiant heat impacted rapidly on the steelwork adjacent to the pit, requiring urgent cooling. Water fall out into the pit only increased the fire intensity. Increasing radiant heat levels forced the hose operator to retreat to a cooler position. (*Photo BP/ Resource Protection International.*)

The same LNG retention pit fire after high expansion foam application. Flame height and radiant heat have dropped dramatically with 90% radiation reduction achieved. This clearly demonstrates the effectiveness of high expansion foam systems. (*Photo BP/ Angus Fire.*)

In the live fire test shown above, high expansion foam is applied onto a burning LNG contained pit fire. The fire intensity is clearly reduced as is the radiant heat level. The fire will continue to burn as it is not possible to extinguish an LNG fire with foam of any type (dry chemical powder could be used). However, the ice tube principles shown above mean that the ongoing fire is dramatically reduced in size. Thus, high expansion foam can be effectively used to limit heat input to adjacent tanks or plant and equipment. (*Picture courtesy Resource Protection International*.)

For LNG spills outside of contained areas, it may be possible to use medium expansion foam application as part of a portable response. The actual spill conditions will dictate whether this approach is safe and practical and it may be that limited spills will vaporize before such a portable response is ready.

Applied foam gradually degrades as water in the foam bubbles slowly drains out. This in combination with foam losses through direct flame impingement and radiant heat (evaporation) means there will be ongoing foam blanket losses. For LNG fire control/reduction, foam will need to be re-applied regularly until all the LNG has been burnt off. It should be obvious to responders when the foam blanket needs re-application due to the increase in fire size.

8.4 Extinguishment of LNG fires

The only effective method for extinguishing an LNG fire is to use dry powder. It is quite possible to extinguish an LNG spill fire using dry chemical, either as a fixed fire system or wheeled or hand held extinguishers.

It is equally possible to extinguish a natural gas or LNG jet fire using dry powder. However, as with any pressure fire, or indeed any flammable liquid fire, once the fire has been extinguished, the vapour remains and a vapour cloud can quickly develop under pressure.

Therefore, although dry powder is very effective, its use must consider post extinguishment vapour formation and movement as this may create a higher hazard than the extinguished fire.

LNG spill fires can be extinguished using dry chemical in the same way as other flammable liquid fires can be extinguished. If anything, LNG contained fires are less difficult to extinguish than typical hydrocarbon contained fires, using dry chemical.

However, the same principles of limited post fire security and high potential for re-ignition must be recognized and understood.

There is also the question of vapour migration once the fire is extinguished. It is therefore necessary to carefully consider the impact of extinguishing an LNG fire.

The method of using dry chemical for extinguishing LNG fires is the same as that for any other flammable liquid. The photo above shows dry chemical used on a typical kero-based flammable liquid. (*Picture courtesy Resource Protection International.*)

The photo above shows dry chemical used on an LNG pit of 10 m^2 (107 sq ft). Such relatively small area fires can be easily dealt with using portable extinguishers. (*Picture courtesy Resource Protection International.*)

Dry chemical units

Various sizes of dry chemical units are available for use at terminals.

Typically, 12 kg (30lb) units should be the minimum for a site. Wheeled units should be in the order of 50 kg to 100 kg (110 lb to 220 lb).

Trailer dry chemical units up to 1500 kg (3,300 lbs) and more are possible but these must consider means of transport and access as well as manpower to deploy.

One important aspect of large output dry chemical nozzles is that the powder cloud created can easily block the unit operator's vision of the fire area, making it difficult to get the aim and sweep correct for extinguishments.

It may therefore be necessary to have one person at right angles to the fire and dry chemical unit to assist in the powder stream direction, to be fully effective. This is certainly true for large fires.

Large output chemical monitor nozzles can reduce and block vision. The cloud created as shown in this photo can make it difficult to see the effectiveness of the application.

Fixed dry chemical systems

Fixed dry chemical systems offer the possibility of extinguishing an LNG fire but the chemical stream is subject to wind speed conditions and this has to be considered for the specific location.

Fixed systems may be provided either at jetties to cover the loading manifold area or at onshore facilities if a need for rapid extinguishment is identified. It is re-emphasized that the impact or consequences of extinguishment—a vapour cloud—must be carefully considered.

In this photo of a fixed dry chemical system discharging, the effects of the wind can be clearly seen. The issue of post-fire security must also be noted if such systems are considered. (*Picture courtesy Resource Protection International*.)

The number of nitrogen cylinders required for large dry chemical systems has also to be considered in terms of space of jetty locations. (*Picture courtesy SIGTTO*.)

Dry chemical type

Only good quality chemicals which have a proven track record in extinguishing LNG fires should be considered. Potassium bicarbonate and potassium bicarbonate/urea are particularly effective chemicals for LNG fire extinguishment.

All powders must be compatible with the foam type to be used at facilities. ‘Standard’ bicarbonate powders should not be used. If in doubt, live fire tests should be conducted to determine the most suitable type for use nationally.

Fixed water curtains/screens

Fixed water curtains can limit LNG vapour migration and act as a barrier if properly designed. The need for a barrier or need to influence the vapour cloud or dilute the cloud may involve, for instance, a source of ignition downwind of potential release areas, or to prevent off-site migration to third party or public areas.

Latest fire school work, which uses all data from gas imaging recordings, indicates that correctly positioned mass water curtains can substantially reduce vapour migration and there is some confidence that good design of curtains can be an effective barrier for vapour control.

Typical fixed water curtain nozzle. Various designs are available according to the water curtain objectives. If the aim is to limit or prevent radiant heat, then the piping and the nozzles themselves may need to be rated for a specified period of fire resistance. Conventional steel or brass materials may not be adequate. (*Picture courtesy Resource Protection International.*)

Typical fixed water curtain patterns. Like the dry powder systems, water curtains may be subject to wind effects and careful study of the location and prevailing wind direction is necessary if the curtain is to be effective and not to contribute to vaporization or increased fire size. (*Picture courtesy Resource Protection International.*)

Fixed water curtains, as shown above, may be used as a barrier against radiant heat and act as a protected escape route for personnel. These may be used on jetty heads or approach roads.

Another example of water curtain as personnel protection for escape purposes. (*Picture courtesy Resource Protection International.*)

Portable water curtains

Portable water curtains use the same principles as the fixed hardware design with hose used to provide the water. If there is a need for a practical response to provide a water curtain barrier for a limited size gas release or to assist gas dilution during a limited size gas release then a portable response may be used. It is important to note that fire responders must be fully protected against flash fires when deploying water curtains.

An example of a portable water curtain nozzle (*Picture courtesy Resource Protection International.*)

In the test shown below, the water curtain on the left of the LNG vapour cloud to the right acts as a barrier with the water acting to increase vaporization and dilute the vapour. One aspect of this curtain is that mainly methane gas tends to rise up the water curtain and continue to rise thereafter.

(*Picture courtesy Resource Protection International.*)

Water spray/deluge

Water spray systems

Water spray systems are systems designed to apply water at a predetermined application rate to protect specific equipment or areas. Water has high heat absorption capability in terms of its specific heat and latent heat of vaporization. The major cooling effect is brought about by the vaporization of water.

Water spray systems can be used for effective cooling of structures, plant and equipment. Application rates are listed in NFPA and EI (Energy Institute) Codes (EI was formerly the Institute of Petroleum) according to the cooling objectives—either for radiant heat protection or for flame impingement protection.

Energy Institute Model Code of Safe Practice: Part 19 - Fire Precautions at Petroleum Refineries & Bulk Storage Installations.

Part 9 - Bulk Pressure Storage and refrigerated LPG.

NFPA 15 - Water Spray Fixed Systems for Fire Protection

Care has to be exercised when designing a water spray system. The spray nozzles can become blocked by corrosion particles or poor water quality. Corrosion resistant materials and good quality nozzles are necessary.

Water spray system in operation. Remote actuation is often necessary to ensure safe operating of the system. (*Picture courtesy Resource Protection International.*)

Use of small diameter holes drilled in water piping for cooling spray systems shall be avoided. The small outlets easily become blocked.

A very important design point to note is that if the water is near to a burning LNG pool, the fallout water droplets getting into the LNG will cause a higher rate of vaporization and the fire will obviously increase in size.

Water monitors

Water monitors, both fixed and portable, may be used for cooling structures, plant and equipment to protect against radiant heat or flame impingement.

Fixed monitors may be of the manually operated and directed type that requires personnel to actuate and operate. There is also the option of using oscillating monitors which, once actuated, can apply a water stream over a pre-determined area according to the settings of the oscillation pattern.

Wherever possible, the water supply requirements for, and actuation of monitors should be determined through site-specific scenario analysis.

Portable monitors are also an option for cooling but the number of monitors to be used must consider the available manpower to deploy, actuate and direct such monitors. It is possible to use portable oscillating monitors where manpower is limited.

Fixed water monitors will need manual intervention to direct water streams to be fully effective in covering a large and/or wide area. (*Picture courtesy Resource Protection International.*)

Use of oscillating fixed monitors reduces manpower intervention requirements but the oscillation pattern needs to be carefully considered. Remote actuation is also preferred for minimum manual intervention. (*Picture courtesy Resource Protection International.*)

Firewater systems

Terminal onshore firewater systems should be designed in accordance with Companies Engineering Technical Practices requirements and firewater pumps and systems should conform to NFPA 20.

The need for manual fire intervention where responders would connect to fire trucks from fire hydrants, or where a site fire team or trained operators would use hose and nozzles directly from site fire hydrants should be carefully considered for LNG facilities.

For an import facility, whilst a mobile and portable response to an LNG spill or a release incident is feasible, this would normally only be considered where the spill or fire was relatively small, possibly only several metres diameter and contained by kerbing or bunding. LNG spills or fires above this size should be drained and diverted to retention/containment pits and if necessary, perhaps as a code requirement or due to close proximity of structural or fixed assets or ships etc, a high-expansion foam system should be provided.

Therefore, fire hydrant numbers and locations should consider possible scenarios as the basis for requirements. Note that buildings, diesel and odourizer facilities will require hydrants.

For liquefaction facilities, where other hydrocarbons may be in use as refrigerants, the need for hydrants and a mobile/portable response will obviously be necessary, but again, their needs should be assessed via possible scenarios.

9 Emergency response plans

9.1 Scenario-specific emergency response plans

LNG facilities should have emergency procedures in place for higher-level control of an incident. For potential LNG emergencies, generic and specific Emergency Response Plans (ERPs) should be prepared for credible serious or major incidents at facilities.

The identification and assessment of potential credible scenarios should follow the procedures and methods laid out in industry and company guidance. From the scenarios and the listed response actions to the scenarios, emergency response plans are developed.

The ERPs should be:

- based on potential credible serious or major scenarios for that facility;
- relevant to the facility systems and equipment (site specific);
- fit-for-purpose;
- easy to use;
- helpful to the end users.

Preferably, ERPs should consist of a single front page of text intended as guidance and instruction for incident responders, whilst on the reverse of the text page, an ‘effects’ map is provided.

This effects map should indicate either the potential LNG pool fire area, or LNG vapour cloud showing downwind distance to LFL for specific releases.

The ERP purpose is to provide instant written instructions, guidance and helpful information for personnel to assist them at the critical early stage of a serious or major incident and to provide sufficient potential hazard information to enable informed decisions on the safety of personnel responding to the incident.

The ERPs are intended to provide guidance for the first 20 to 30 minutes of the incident and indicate the actions and resources required to deal with the incident during this time. Once this period of time elapses, a stable response should have been established and if the incident duration should be prolonged, an ongoing strategy for dealing with this should be developed by those managing the incident.

The ERPs should be developed from detailed analysis of potential credible major incidents. This is usually done in the form of scenario worksheets that will study the incident consequences, prevention measures, mitigation measures and response measures.

The main aspect of the worksheets is the response strategy. As emergency response strategies for LNG facilities, the following should be considered as the base response which can be expanded into incident specific emergency response plans for LNG facilities.

Gas cloud response strategy

- Avoid water in the liquid pool as this only increases cloud size.
- Check for gas drift to semi or fully-confined areas where an explosion may be possible.
- Use of high expansion foam for vapour reduction.
- Water curtains can dilute and divert gas.
- Water monitors may offer limited dilution.
- Wear full bunker gear and SCBA in case of flash fire.

LNG pool fire response strategy

- Cool any heat or flame affected steelwork or plant.
- Avoid water in the burning pool as this only increases fire size and radiant heat distance.
- Foam can reduce fire size (radiant heat reduction).
- Dry powder can be used, but the gas cloud will remain.
- Combination fixed foaming to reduce for approach and dry power for extinguishment, or dry powder knock down and foaming thereafter to reduce vaporization.
- Wear full bunker gear, and move upwind on any extinguishment.

Jet fire response strategy

- Isolate pressure source (pumps/operations).
- Prioritize cooling.
- Cool any flame affected steelwork or plant.
- Cool radiant heat affected steelwork/plant.
- Foam cannot extinguish pressure fire.
- Dry powder may extinguish jet fires, but pressure gas clouds will remain.
- Full bunker gear is required due to high levels of radiant heat.

Road tanker liquid spill response strategy

- Deal with this in the same way as an LPG road tanker.
- Give priority to evacuation to a distance of one mile.

- Use water curtains if a gas cloud is present to dilute/contain/divert.
- Avoid water on LNG liquid as this will increase gas cloud.
- Evacuate all responders once water curtains are in place.
- Wear full bunker gear and SCBA in case of a flash fire.

Road tanker spill fire response strategy

- Deal with this in the same way as an LPG road tanker.
- Give priority to evacuation to a distance of one mile (1.6 km).
- Cool the tanker if on fire but expect greater fire intensity if liquid LNG is involved in the fire.
- Cool any nearby plant, equipment or other heat affected exposures.
- Evacuate all responders once cooling is in place.
- Wear full bunker gear because of high levels of radiant heat.

Jetties gas cloud strategy

- Same as for LNG gas cloud response strategy.

Jetties pool fire strategy

- Same as for LNG pool fire response strategy.

Jetties spill strategy.

(Where a run-off channel is provided to the containment basin).

- Activate hi-ex foam coverage in channel and basin.

Ship manifold gas cloud strategy

Onshore FD

- Contact ship master and confirm jetty head/ship conditions and gas cloud conditions.
- Strategy generally the same for LNG gas cloud response strategy.

Ship actions

- Halt cargo operations and actuate water spray system for gas cloud control/dilution.
- Ensure ship fire pump is running.
- Monitor gas detection for gas migration on ship.
- Leaking LNG loading line isolated and drained down.
- Prepare ship dry powder system in case of ignition.
- Prepare ship-cooling monitors ready in case of ignition.
- (Manifold incidents should be short-lived due to isolation valves and emergency shutdown capability.)

Ship manifold pool fire strategy

Onshore FD

- Contact ship master and confirm jetty head/ship conditions and gas cloud conditions.
- Strategy generally the same for LNG pool fire response strategy.

Ship actions

- Halt cargo operations.
- Alert port authority/other shipping in docks and request fire tugs.
- Onshore operator actuate jetty monitors and high-ex foam pourers if beneficial for fire control.
- Actuate ship water spray system and ensure fire pump is running.
- Monitor gas detection on ship.
- Ship fire team in full PPE and SCBA move to available water monitors if safe to do so.
- Isolate and drain down LNG line if safe to do so.
- Direct monitor cooling streams on to flame and radiant heat affected piping, valves, manifold and steelwork.
- Advise shore control room and/or fire tugs of fire extent and conditions.
- Consider the best strategy – continue cooling or use ship/shore dry powder to extinguish.

10

Personal protective equipment (PPE)

10.1 Plant operators

Apart from normal PPE requirements for plant operations, where duties involve potential contact with cold vapours or LNG liquid, a face shield or even a face shield with hood should be worn. When considering face and eye protection, the materials used should not be subject to shattering or disintegration on contact with cryogenic materials.

If using a face shield, care must be taken to prevent lighter-than-air natural gas vapours from entering the shield and causing some degree of localized containment and asphyxia. In addition to eyes and face, protection should also be provided for exposed areas of the neck and head.

10.2 Breathing apparatus

The US Bureau of Mines has tested Self Contained Breathing Apparatus (SCBA) for operation at −32°C (–26°F). Under this operating temperature, the regulator diaphragm frequently stiffened, which can cause erratic air flow and high resistance to inhalation. Face mask exhalation valves also froze shut when the moisture condensed around the exhalation valves and froze over. It was found that the moisture might be loosened by exhaling hard into the face mask but where this did not work, thawing out was required.

Condensation also created face mask fogging conditions although the use of a nose cup reduced this tendency. Harness, straps and connections of solid plastic or similar materials became stiff and unmanageable when cold. Nylon webbing however, did not do so.

The following are the principal recommendations made by the Bureau for SCBA in low temperatures.

- Use a face mask fitted with a nose cup.
- If possible, avoid storing or pre-cooling the set at low temperatures.
- Use special parts for low temperature operation whenever necessary.
- Additional tightening of valve packings and threaded connections may be necessary to stop high-pressure leaks.
- Do not over-tighten cold valve packings and threaded connections. This will avoid damage when brought back to room temperature.

- Dry off exhalation valves before exposure to low temperatures to prevent them from freezing shut.
- Do not add additional air to a cylinder after pressure in a fully charged cylinder has dropped due to a decrease in temperature.
- Check the operation of the apparatus in low temperature before using it in a hazardous atmosphere.

It must be emphasized that the only scenarios envisaged where SCBA may be worn at LNG facilities would be for building incidents for fire search or casualty search and rescue.

The need to wear SCBA within or close to an LNG vapour cloud is not recommended due to the ignition hazard. However, it is recognized that situations may arise where a rapid, snatch type rescue may be necessary, and that SCBA may need to be worn in case of flash fire or for protection against cold vapours.

If so, the SCBA set can only be worn with full bunker gear as described under PPE below.

10.3 Responder personal protective equipment (PPE)

Apart from necessary protection against fire and radiant heat effects, fire bunker gear PPE can also protect against the personal injury hazards presented by LNG as a cryogenic liquid.

The main hazards from LNG are obviously contact with liquid LNG that will result in rapid frostbite, from superficial to severe.

Clearly, as a cryogenic liquid, any immersion of the skin will have serious results and must therefore be avoided. Contact with cold surfaces, such as piping or steelwork involved in LNG liquid duty, can result in skin bonding and serious injury.

Prolonged exposure to cold LNG vapour can also lead to health hazards including frostbite, breathing discomfort and in some cases, hypothermia.

Small experiments have shown that good quality fire bunker gear will protect against accidental LNG liquid spillage/splash and will also protect against cold vapour ingress. However, any of these situations must be viewed as short-term exposure protection and not as prolonged protection.

For LNG fire and emergency response, the requirements for responders should always be:

- full coat and pants set (bunker gear);
- Nomex anti flash hood;
- fire helmet with visor;
- fire gloves;
- fire boots.

BP has also been testing an LNG specific bunker gear (turnout gear) clothing programme that gives the same level of protection to either the EN 469 or

NFPA 1971 (2000) standards, yet is also significantly lighter for wearing in hot weather climates where the traditionally heavy gear causes stress to the wearer over time.

Splash protection and anti-penetration barriers are part of the LNG specific bunker gear considerations, including resistance to icing of fibres when exposed to limited splashes. However, such PPE can only ever give limited protection and even then only against accidental minor splashing.

For further reference, consult your company specific guidance.

11

Codes and standards

11.1 Construction and operation of LNG facilities

The following lists the codes, standards and regulations and regulators governing the construction and operation of LNG facilities.

US regulations

- **49CFR (Code of Federal Regulations) Part 193** *Liquefied Natural Gas Facilities: Federal Safety Standards*

The first federal code was prepared and adopted in July 1976 as a result of a mandate from Congress to regulate the safety of the LNG industry. The basis of the original DOT code was essentially the already published NFPA 59A. Although the structure and format are different, the requirements are similar. In March 2000, the federal code adopted large portions of NFPA 59A, but there are areas the regulators felt were lacking that have additional requirements in the code. The code anticipated large land-based LNG facilities, specifically the peakshaving industry and import terminals. Smaller plants and temporary facilities were not envisioned, and therefore, many of the provisions are not easily applied to remote satellites or other small facilities. 49CFR Part 193 covers siting requirements, design, construction, equipment, operations, maintenance, personnel qualifications and training, fire protection, and security.

- **33CFR Part 127** *Waterfront Facilities Handling Liquefied Natural Gas and Liquefied Hazardous Gas*

This federal regulation governs import and export LNG facilities or other waterfront facilities handling LNG. Its jurisdiction runs from the unloading arms to the first flange outside the LNG tank.

33CFR Part 127 has the following major headings: General; Waterfront facilities handling liquefied natural gas; and Waterfront facilities handling liquefied hazardous gas.

- **NFPA 59A** *Standard for the Production, Storage and Handling of Liquefied Natural Gas (LNG)*

The *NFPA standards are developed by volunteer committees and have no legal standing. They are not laws or regulations*. The standards are widely used and are often adopted by cities or states by reference. The standards carry the weight of law only if incorporated by reference by jurisdictional authorities.

NFPA 59A has the following major headings: Introduction; General plant considerations; Process systems; Stationary LNG storage containers; Vaporization facilities, Piping systems and components; Instrumentation and electrical services; Transfer of NG and refrigerants; Fire protection; Safety and security; Alternative requirements for vehicle fuelling for industrial and commercial facilities using ASME containers; Referenced publications; Appendices; and Indices.

- **NFPA 57** *Standard for Liquefied Natural Gas (LNG) Vehicular Fuel Systems*

This standard's first edition was in 1996, and it developed in response to the growth of the natural gas vehicle industry in the early 90s.

The regulation covers systems on-board vehicles and infrastructure storing 70,000 gallons of LNG or less. The major headings are: Introduction; Vehicle fuel systems; LNG fuelling facilities; Installation requirements for ASME tanks; Fire protection; Safety and security; Referenced publications; and Explanatory material.

US regulators

- Federal Energy Regulatory Commission (FERC);
- Department of Transportation (DoT);
- State Agencies and Public Utility Commissions;
- Local Jurisdictions, *i.e.*, city and county agencies (may include air pollution boards, water and sewer departments, and the local fire department).

International regulations

- **BS7777 and EN1473** – The European Norm standard EN1473 *Installation and equipment for liquefied natural gas—Design of onshore installations.*

  The EN evolved out of the British Standard 7777 in 1996. The standard is very different from the US standards in that extensive risk assessments are required for the design of the facility. The standard is much more detailed and prescriptive. The major sections of the standards include: Foreword; Introduction; Scope; Normative references; Terms and definitions; Safety and environment; Liquefaction plants; Storage and retention systems; LNG pumps; Vaporization of LNG; Pipework; Reception/send out of natural gas; Boil off recovery and treatment plants; Auxiliary circuits and buildings; Fixed protection equipment; Control systems; Construction; Commissioning and turnaround; Painting; Fire proofing and Embrittlement protection.

- **API 620 Appendix Q**

  Covers the design and construction of aboveground single containment tanks. This code permits partial height hydro testing, generally applying a static pressure at the base of the inner tank equal to 1.25 times the maximum static head in operation. This code does not apply to double or full containment tanks (BS7777), nor aboveground membrane designs or concrete tanks. There is no plate thickness limit required.

- **BS7777:1993**

  This applies to flat bottomed, vertical, cylindrical storage tanks for low temperature service. This code is applicable to aboveground single, double and full containment designs with inner containers of 9% nickel steel. It does not apply to designs where both containers are of pre-stressed concrete. Partial height hydro-testing is replaced by full height testing. The maximum plate thickness is 40 mm (1.6”).

- **PD-7777:2000**

  This is a supplement to BS7777, which allows partial height hydro testing. There is no plate thickness limit as far as the authors are aware. It requires expensive, high strength, very high nickel (Hastelloy type) weld filler metal to meet the toughness test requirements on the weld metal.

- **EN 14620: 2006** *Design and Manufacture of Site Built, Vertical, Cylindrical, Flat-bottomed Steel Tanks for the Storage of Refrigerated, Liquefied Gases with Operating Temperatures Between 0°C and −165°C (32°F and –265°F)*.

  This standard was issued in December 2006 and replaces BS7777. It covers similar headings as listed in BS7777. *Parts 1 to 5 cover Site Built, Vertical, Cylindrical, Flat Bottomed Steel Tanks with operating temperatures between −5 and −165°C (23°F and – 265°F)*.

  It is applicable to single, double and full containment tanks, membrane tanks and spheres. It does not apply to designs where both containers are of pre-stressed concrete. This new code permits partial height hydrotesting when ‘crack-arrest’ quality steels are used. The maximum plate thickness is 50 mm (2”).

11.2 Fire protection codes and standards

The following are the main, though not the only, fire protection codes, standard and guidance documents for LNG facilities.

- NFPA 11 – *Foam Systems*;
- NFPA 15 – *Waterspray Fixed Systems*;
- NFPA 17 – *Dry Powder Systems*;
- NFPA 20 – *Fire Water Pumps*;
- Company specific Engineering Technical Practices.

Acronyms and abbreviations

AIT	Auto Ignition Temperature
bbl	Barrel (typically 42 US gallons)
BLEVE	Boiling Liquid Expanding Vapour Explosion
BS	British Standard
BTU	British Thermal Unit
Btu/hr-ft^2	BTU per hour per square foot
CFR	Code of Federal Regulation
Cryogenic	Low, sub-zero temperature.
Embrittlement	The process where certain metals, such as carbon steel, lose their ductility at cryogenic temperatures and become brittle.
EI	Energy Institute (formerly known as Institute of Petroleum)
EN	European Norm
ERP	Emergency Response Plan
Foam	Mix of water and either synthetic or fluoroprotein concentrate to create stable bubbles which will float on LNG in order to reduce LNG vapour and/or fire size.
Insulation	Layer, powder, block, coating or other application which maintains a given temperature or temerature range.
IR	Infra red (flame or gas detection).
kW/m^2	Kilowatts per metre square
LFL	Lower Flammable Limit.
L/min/m^2	Litres per minute per metre square.
LNG	Liquified Natural Gas. The gas in its liquid state.
LPG	Liquified Petroleum Gas.
m	Metre (100 centimetres, 1000 millimetres)
m^3	Cubic metre

NFPA	National Fire Protection Association
Perlite	Non combustible, natural siliceous rock or volcanic glass.
PPE	Personal Protective Equipment
RPT	Rapid Phase Transition.
SCBA	Self Contained Breathing Apparatus
SIGTTO	Society of Industrial Gas and Tanker Terminal Operators

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- CAFCO International
- Flameout: Michael Moore
- Hale
- Honeywell Analytics (in Texas, represented by Detection & Measurement Systems, Inc—Ray Peacoe)
- International Coatings Ltd
- Knowsley
- Micropack: Adrian Lloyd
- MEDC

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16. Society of Industrial Tanker and Terminal Operators (SIGTTO) Liquefied Gas Fire Hazard Management (2004).

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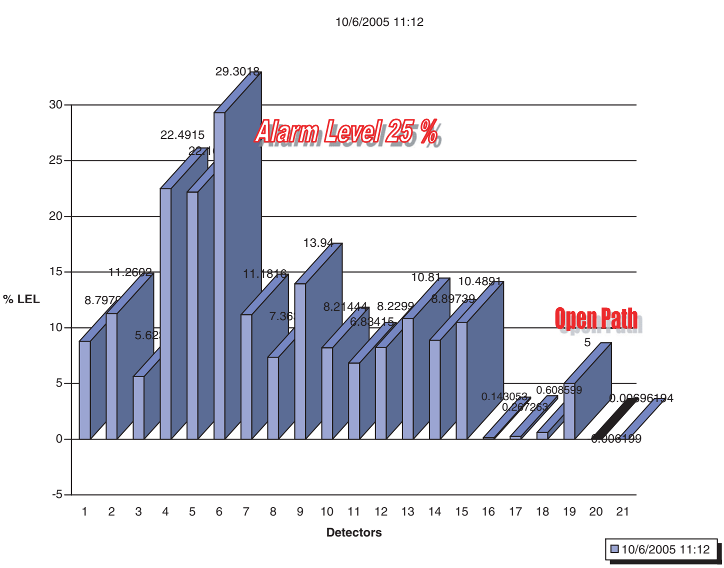
Appendix A: Gas detection test work analysis

Using gas-imaging technology, it has been possible during the BP LNG Fire School tests to chart gas detectors' response to LNG vapours from the retention pits. The following coarse data is available at this time.

The following graph is a one-second view across the grid of 18 point IR detectors that were placed along the open path detectors on the east side of the LNG Marine Pit (slop tank side).

With almost 3,000 US gallons (11,355 litres) of LNG in the 65 m^2 pit (700 ft^2), this graph shows that in this particular case, the open path IR gas detector has peaked, but only one of the point gas detectors is showing a 'low level' alarm.

Had this been a real time LNG release event, with the way industry typically places point detectors and sets the alarm levels, this particular release could have been completely missed if reliance was on point detection only.



Usually with point detection, there are two or three detectors placed and voting as an alarm. Two out of three would be an alarm, but here, the outcome was 1 out of 18.

This test and the following graph certainly shows that open path is the way forward for LNG facilities.

In the graph on page 110, foam was applied to the same pit and measurements taken from the gas detection.

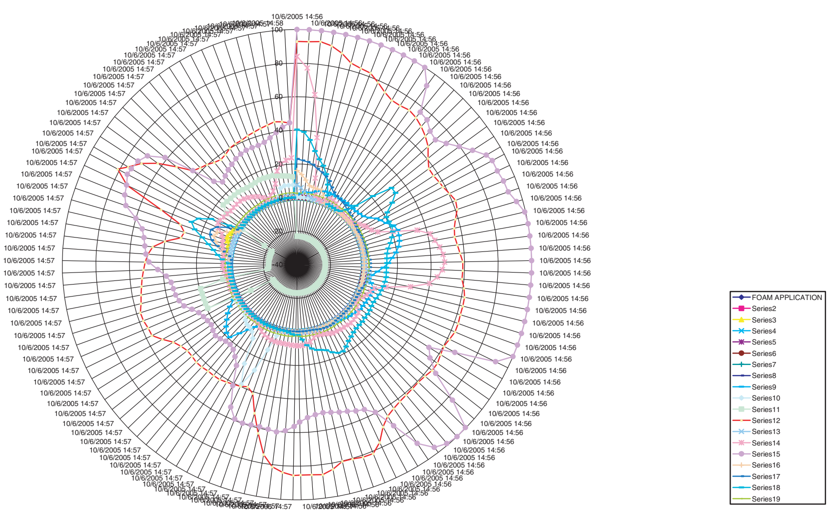
LNG was applied and then allowed to reach steady state vaporization. High expansion foam was then applied at 500:1 ratio and at 10 litres/min/m^2 (0.25 US/gal/ft^2/min).

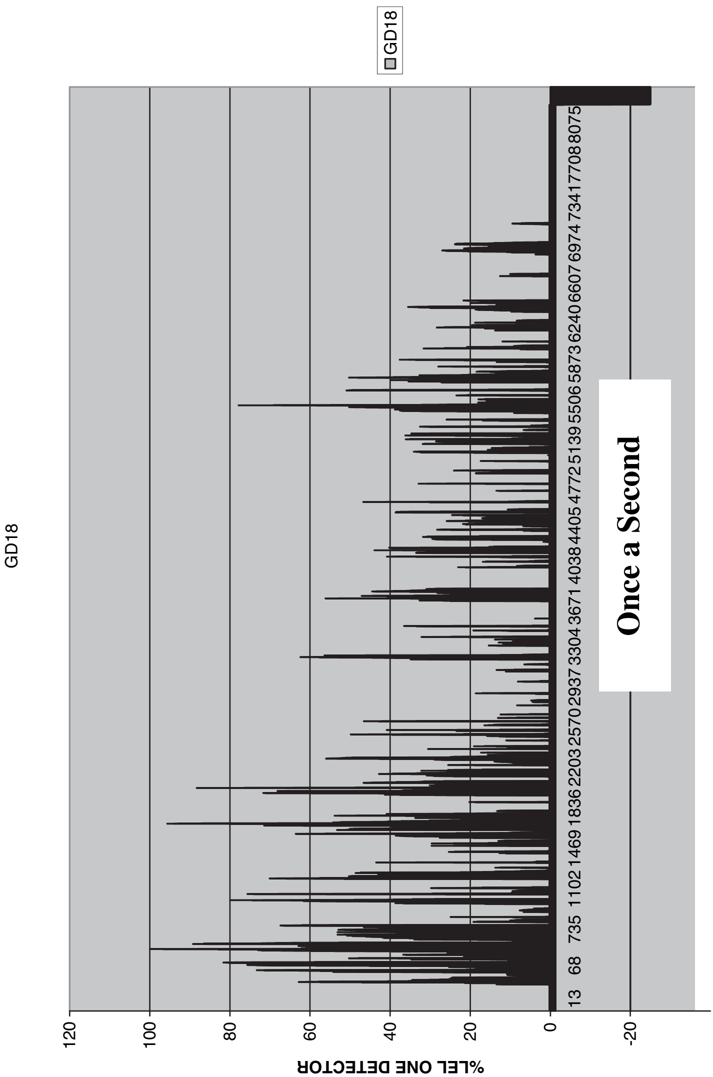
The graph should be considered as a 60 second clock and each detector with a serial number. Note that 1 to 18 are point IR gas detectors and 19 is the open path IR gas detector.

It will be noted that the applied foam, although slightly increasing the gas levels initially, settles over the LNG and subsequently reduces by over 60% the LFL, and therefore LNG, vaporization on all detectors.

This is independent confirmation that a good quality high expansion foam can reduce vaporization by up to 60% and thereby reduce vapour cloud distance to LFL.

Previously, such quantification has been difficult to provide. The tests here demonstrate the theory adequately.




GD18
GD18
%LEL ONE DETECTOR
120
100
80
60
40
20
0
-20
13 68 735 1102 1469 1836 2203 2570 2937 3304 3671 4038 4405 4772 5139 5506 5873 6240 6607 6974 7341 7708 8075
Once a Second

Appendix B: Foam system design considerations

The following has been produced as a result of the extensive testing of foam expansion ratios, foam application rates, and foam application hardware at the BP LNG Fire School, Texas A&M University. The document is produced in collaboration between BP, Resource Protection International, Texas A & M Fire School, Angus Fire, Zellweger Analytics, Micropack and Flameout.

National Fire Protection Association (NFPA)

Because of its significance worldwide the NFPA 11:2005 document needs specific consideration. NFPA is a minimum set of standards, codes and guidelines, with the emphasis on minimum. Care is needed to ensure the specifics of any particular LNG fire protection system have been thoroughly considered and subjected to practical test evaluation so a 'best practice' can be developed on any particular aspect of protecting against an LNG escape.

NFPA11:2005 clearly stipulates in chapter 6 that 'the discharge rate per unit area shall be established by tests and shall be able to achieve a positive and progressive reduction in radiation within the time limitations established in the analysis'. It also states that 'tests often give minimum application rates and are conducted under ideal weather conditions with no obstructions or barriers to fire control. The final design rates are generally three to five times the test rates'.

'The analysis shall consider effects of the heat exposure on adjacent plant equipment' is required by sub-section 6.14.1.2. This is followed by Annex C.1 (6) which states 'For LNG fires, high expansion foam will not normally extinguish a fire, but it will reduce the fire intensity by blocking radiation feedback to the fuel'.

It is often preferred not to extinguish LNG fires as the evolving gas is burnt off in a controlled way until the incident can be declared over. Premature extinction can build invisible vapours, which if caught in a confined space with ignition potential could cause an explosion. After initial radiant heat reduction, the residual LNG should be burnt off through the foam blanket under controlled conditions with regular foam top up.

Foam and equipment should also be proven by tests on LNG, before selection for use in operational facilities. The determination of such high expansion system designs shall depend on an analysis specific to the individual site.

NFPA 59A Section 9.1 states that such protection shall be based on sound fire protection engineering principles and determined by an evaluation of local conditions, hazards and property exposure. Other sections of NFPA 59A note that ‘new technology may be applied and tests directly related to the fire risk shall be duplicated’ and in this respect the BP LNG Fireground at Texas A & M fulfils these requirements. Multiple real time fire tests with LNG liquid have been carried out in duplicate containment basins and repeatedly the depth of foam required to effectively cover the LNG, mitigate the flames, reduce the radiated heat by 90% or more, is a minimum of 1.2 m (4 ft).

It is now clear that many of the frequently quoted low application rates of the past are inadequate for a more typical operational LNG fire, where speed of control becomes a vital factor. An application rate of 10 litres/min/m^2 has proved to be the minimum requirement in the BP LNG fireground test work at Texas A&M under the most stringent and realistic operational conditions, and shall now be used in LNG facilities.

This proven rate will inevitably be more expensive than some of the lower rates since more equipment will be required to provide effective rate of foam production and sufficiently rapid speed of coverage.

This has been shown to be necessary to provide quick, effective and reliable protection. Lower levels of protection may do little to adequately protect personnel and plant in a real LNG fire scenario and should be considered false economy.

Specialized LNG generators must be selected

In reality, larger sized pool fires are likely to occur where the foam generators can be subjected to direct flame impingement and ongoing radiated heat for around 45 minutes or longer duration. Temperatures have been measured between 1,000 and 1,200°C (1832 – 2192°F) in such fires. Unless the foam turbines, bearings, fan, body and foam making nets are specifically uprated and protected to withstand such heat levels/conditions, there is an obvious risk they will fail before the fire is under control, which would render the whole fire protection system inadequate.

The Angus Fire LNG Turbex 500:1 high expansion foam generators used in the BP/Texas A&M LNG training schools overcome all these difficulties and have repeatedly been shown to be highly effective.

There is evidence that standard industrial high expansion generators will quickly fail if subjected to such fire conditions that the fire will not be brought under control. In some instances, the bodies are made of simple alloys that cannot withstand such high temperatures, even for a few minutes.

Foam production will rapidly cease as bearings and fans within industrial units begin to meltdown or seize up with thermal expansion. Bodies and nets can also distort and bind on fan blades to prevent correct operation.

Fan-less blower type generators are not an adequate alternative as these units are easily starved of air by cross winds and changing air directions often caused by the fire itself.

The expansion ratio and stability of the foam bubbles produced can be adversely affected with a sudden delivery of a very wet foam directly into the LNG pool which could lead to sudden flare ups and fire intensification, with associated danger to personnel and unexpected exposure hazards.

Electric motors even when flameproofed should not be used to power such foam generators for LNG applications as they cannot be relied upon to operate correctly across the full operating temperature range of −164°C (–263°F) up to around 1,200°C (2,192°F).

It is therefore imperative that only specially modified fan driven water powered high expansion generators should be used in LNG facilities, which are proven to be effective on LNG pool fires of at least 6” (150 mm) LNG depth over a 65 m^2 (700 ft^2) (or greater) concrete impounded area.

Comments and conclusions

- NFPA 11 covers the full range of uses of all types of foam from low to high expansion and from use on buildings, ships, aircraft, commercial and industrial structures as well as within the oil and gas industry. It covers the use of foams for creation of inert spaces, vapour suppression and fire suppression. As such, by reading one paragraph or section out of context with the remainder of the standard and its referenced informational publications in Annex 1 on page 11–80, is to run the risk of totally misunderstanding the detail of the protection that should be provided for the specific risk being addressed.
- In the case where the risk is LNG (as a flammable liquid/vapour) it is NFPA 11 sub-section 6.12.5.2.1.2 that specifically applies to the depth of foam required for LNG and states ‘the required depth shall be permitted to be considerably greater and no less than the depth determined by tests. Tests shall duplicate the anticipated fire event in the protected area’.
- Some contractors, consultants and others may justify on historical test data that 3.6 litres/min/m^2 (6 cu.ft/min/sq.ft) is adequate for LNG applications. This offers no safety margin allowance which is essential for operational duty in a modern LNG facility.
- Hence all the test work at Texas A&M on the BP Fire Ground where only the rate of 10 litres/min/m^2 (0.25 US/gal/ft^2/min) foam solution flow achieves the required fast levels of fire control, which has consistently been shown to be effective. With this application rate and rapid response from the high expansion foam generators, radiation reductions have been achieved of around 90% within 60 seconds from LNG gas ignition.

Therefore specifications should require foam of 500:1 to deliver 80–90% radiated heat reduction within 60 seconds of LNG ignition (including system start-up).

- When deciding on minimum foam depth and taking all the relevant factors into account as recommended in the NFPA documentation, then a minimum of 1.2 metres (4 ft) depth of foam is necessary within containment basins. This minimum depth should be specified in future LNG projects as well as current LNG facilities, and the foam shall be held in place by a permanent containment basin structure.

- The hardware specified must be capable of 500:1 foam expansion ratio, provided with hood and fan drive powered by the water supply to give uniform bubble production. It must be capable of working under LNG vapour and fire conditions where −164°C to +1,200°C (–263°F to +2,192°F) is possible from cold LNG liquid/vapours, to direct flame impingement with the associated radiated heat. Foam generators must be proven under LNG fire conditions. The high expansion type foam shall also be shown to be effective on LNG fires of at least 60 m^2 (645 ft^2) area with the chosen generator.

Equipment, such as:

- Angus Fire LNG Turbex high expansion foam generator skids and hoods;
- Angus Fire Expandol high expansion foam concentrate;
- Micropak and Zellweger flame and gas detection and;
- Ansul Dry Chemical powder,

have been shown to be robust and reliable through frequent use during the bi-annual BP LNG Fire Schools, being subjected to live fire conditions repeatedly.

Other similar equipment that has been tried and tested in the real time live fire scenarios of the BP LNG Fire School would be acceptable, so long as they demonstrate the same level of active, robust and reliable fire protection that will meet BP's stringent requirements.

Way forward

LNG facilities should now insist that a specific foam solution application rate (10 l/min/m^2 (0.25 US/gal/ft^2/min)), reduction in radiated heat (90%) within 60 seconds, and minimum depth of foam (1.2 m (4 ft)) is stated in all tender documents to ensure a level and fair bid process. Otherwise there may be a temptation to provide an inferior system that will not provide the level of protection that has been proved effective, possible and practical to achieve. This will avoid potential failures under emergency conditions.

The overriding objective of BP investing so heavily in and in carrying out the test work at Texas A&M was to clearly define the type and applications for fire protection that will work effectively when required on live LNG fires, spills and vapour releases.

This test work has also defined what is not suitable and likely to put personnel and plant safety at considerable and possibly unacceptable risks.

Work is ongoing to make formal approaches to the various international foam standards committees to have both LNG application rates raised and the time to achieve fire control reduced respectively.

Appendix C: Historical foam application data

Summary of historical and latest LNG test data

Date	Location	Containment pit area m^2 (ft^2)	Appl. Rate L/min/m^2 (US Gall/min)	Control (90% radiant reduction unless specified)
1960–61	**Bureau of Mines** Lake Charles, Louisiana – US	Only pass/fail criteria – no results available		
1963–64	**Tokyo Gas** Japan	Only small scale. Showed high expansion foam worked OK, but no details.		
1971	**Philadelphia Gas Works, USA**	4.5 (50) 500:1 favoured expansion. No other details		
1972	**American Gas Association** Fort Worth, USA Conclusions: High quality foam at 500:1, 4.9 l/min/m^2 required for control in 2 mins. (6 cuft/min/ft^2 = 3.6 l/min/m^2 at 500:1) Extrapolation from this data by Whesson	Wet sand pits 37 (400) 111.5 (1200) 100 (1080)	5.2 (0.13) 4.6 (0.11) 3.4 (0.08)	1m 42 s 1 m 36 s 5 mins

Date	Location	Containment pit area m^2 (ft^2)	Appl. Rate L/min/m^2 (US Gall/min)	Control (90% radiant reduction unless specified)
	(Hydrocarbon Processing Oct 1973) shows an application rate of 13.4 l/min/m^2 (22 cu. ft/min/sq.ft at 500:1 expansion) in 50 seconds control time.			
1975	**British Gas** Moreton in Marsh, UK Conclusions: Expansion 1000:1, 3 min pre-burn with only 2" (50 mm) LNG. Doubts about amount of LNG left after preburn and whether realistic results. 500:1 adopted for actual facility	Soil pit? 74 (800)	9.1 (0.22)	30 s
1975	**American Gas Association – US** Burn rate of 14 mm/min (0.55 in/min)	0.93 (10) dia. (small pans)	11 (18 cu ft/sq.ft at 500:1)	50 s
1981	**Shell Thornton**, UK Pit maybe pre-cooled? Expansion 500:1	Clay pit 36 (387)	6.1 (0.15)	2 m 15 s

Date	Location	Containment pit area m^2 (ft^2)	Appl. Rate L/min/m^2 (US Gall/min)	Control (90% radiant reduction unless specified)
1983	**Gaz de France**, Montoir de Bretagne, France Expansion 300:1	Wet sand pit 200 (2,152) 200 (2,152)	5.8 (0.14) 2.1 (0.051)	1 m 56 s 5 m 50 s
1991	**Shell/Gaz de France**, Nantes, France Expansion 500:1	Insulated soil mound 50 (538)	7.2 (0.17)	80% radiation in 50 s
Sept 2004	**BP/Angus Fire/Texas A&M**, USA Expansion 300:1 **Note:** An MEX1200 unit at around 60:1 operated for further 3 mins but made fire worse as too much water entering LNG pool. Extinguished with 2 × 350 lb dry powder mobiles.	Reinforced concrete vertical sided pit, 1.2 m (4 ft) deep 65 (700) 25s LNG preburn FT2 LNG 300:1 operated for 1 m 40 s Then FT1 LNG 500:1 also operated for further 2 mins	7.15 (0.17) 10 (0.24)	1 m 40 s to 50% reduction (visual only) 3m 40 s 75% reduction (visual only)
Sept 2004	**BP/Angus Fire/Texas A&M**, USA Expansion 500:1	Reinforced concrete vertical sided pit, 1.2 m (4 ft) deep 65 (700) 30 s LNG pre-burn. 8” (200 mm) depth LNG	7.15 (0.17)	8 mins to 70% reduction (visual only) (thread tape and stones in turbine gave faulty result)

Date	Location	Containment pit area m² (ft²)	Appl. Rate L/min/m² (US Gall/min)	Control (90% radiant reduction unless specified)
April 2005	**BP/Angus Fire/ Texas A&M**, USA Expansion 500:1	1.2 m (4ft) deep Concrete basin 65 (700) 20 s LNG pre-burn 6" (150 mm) depth LNG	10 (0.24)	34 s to 98% radiation reduction Foam appl. 1 m 10 s to fill pit under fire.
April 2005	**BP/AngusFire/Texas A&M,** USA Expansion 500:1	Reinforced concrete vertical sided basin, 2.44 m (8 ft) deep with 1.2 m (4 ft) walls above ground 45 (484) 8" (200 mm) depth LNG filled under foam blanket. Ignited vapours above foam. 7 secs preburn 45 (484) 3" (75 mm) depth LNG	10 (0.24) 10 (0.24)	30 s to 92% radiation reduction. Foam appl. 3 m (10 ft) to maintain foam under fire 35s foam application every 2 mins to maintain foam blanket
April 2005	**BP/Angus Fire/Texas A&M,** USA Expansion 500:1 **Note:** More water entering basin from monitor as feed line to sprays failed, helped cause delay in 90% radiation reduction. Wind recorded gusting to 3 m/sec which was also believed to be a contributory factor to this being a very tough test.	2.4 m (8 ft) deep Concrete basin 45 (484) 17" (430 mm) depth LNG water sprays cooling attached steel structure with 3 m/sec (10 ft/sec) wind. Several attacks to extinguish including 3 × 350 lb (160 kg) Sodium bicarb. dry powder trolleys failed. A 2,000lb (910 kg) powder skid with monitor also failed.	10 (0.24)	64% radiation reduction at 43 s. 90% radiation reduction at 4 mins. Thereafter 20 secs foam pulsed every 45 secs for 44 mins until all LNG burnt away and self extinguished.

Notes:

1. **Wet sand and earth pits** may significantly affect the results compared to reinforced concrete, and may help to explain why some of the historical tests have provided faster levels of control at lower application rates. They have often had sloping sides which makes the foam easier to seal against the sides as vaporizing gas is less likely to follow along the pit wall, it wants to move vertically upwards as it is warmed by the foam. Wet sand and earth has a water content which freezes as the LNG arrives to –164°C (–263°F), which absorbs heat from the fire reducing the heat build up in the pit walls before the foam arrives, reducing the attack on the foam blanket as it is applied. The pit is still quite cool when the foam arrives and the full intensity of the fire has therefore not been attacking the foam bubbles during initial application.

   This ‘cooling effect’ does not occur with reinforced concrete pits, requiring a higher application rate to compensate. It was also noticeable how more vapour escapes along the vertical concrete pit walls where the gas finds it easier to force between foam and concrete than between the overlapping foam bubbles in the main blanket.

2. **Raised walls make harder test**

   From the limited test results, the deeper pit seems more difficult to control than the shallower pit, partly because there is more surface area of concrete to get hot in the pre-burn which breaks down the foam on arrival and reduces its effectiveness on the fire. This requires a higher application rate to compensate. Wind effects around the raised walls also force a ‘chimney effect’ to draw more air which fans the flames increasing the radiant heat breakdown effect on the protective foam blanket, also requiring a yet higher application rate to compensate.

3. **Historical tests**

   Measurements often to 90% radiation reduction have been taken historically to define fire control but this does not translate into a specified control time. The recent Sandia report exemplified this in its thermal damage and consequence considerations (Section 3.3.3) where two thermal hazard criteria were considered, firstly reductions below 5kW/m^2 (272 BTU/min/ft^2) radiation levels to prevent 2nd degree skin burns within 30 seconds while structures might be able to withstand higher incident heat flux. Radiation levels approaching 35kW/m^2 (1900 BTU/min/ft^2) will cause significant damage to structures, equipment and machinery within ten minutes. It is therefore important to calculate the primary objective as adequate protection for personnel in the facility, hence rapid fire control is essential.

4. **Final design application rates generally three to five times test rates**

   NFPA 11 Annex A8.20.3 states that ‘Application rates are generally established by specific tests such as that in G4 where the equipment, water supply, fuel and physical and chemical makeup of the candidate foam concentrate are carefully controlled. While these tests can be useful for comparing various foams, they often give minimum application rates because they are conducted under ideal weather conditions with no obstructions or barriers to fire control. The final design rates are generally three to five times the test rates. Thus the rates can vary significantly from one foam agent to another.'

5. **BP/Angus Fire/Texas A&M tests**

   With these tests there has been a specific effort to mirror realistic conditions in an LNG terminal with realistically sized reinforced concrete vertical-sided containment pits located in a hot environment. Hence it is not surprising that in aiming to provide faster and more effective fire control, we have found higher application rates than those historically recorded are essential. Whilst wind has not been a severe hindrance, it was clearly a contributory factor along with water entering the LNG pool to make the April 2005 45 m^2 (485 ft^2) pit test particularly difficult to control.

Appendix D: LNG incidents

Today, LNG is transported and stored as safely as any other liquid fuel. Before the storage of cryogenic liquids was fully understood, however, there was a serious incident involving LNG in Cleveland, Ohio in 1944.

This incident virtually stopped all development of the LNG industry for around 20 years.

The space race, starting in the early 1960s, led to a much better understanding of cryogenics and cryogenic storage with the expanded use of liquid hydrogen (−252°C/−423°F) and liquid oxygen (−182°C/−296°F).

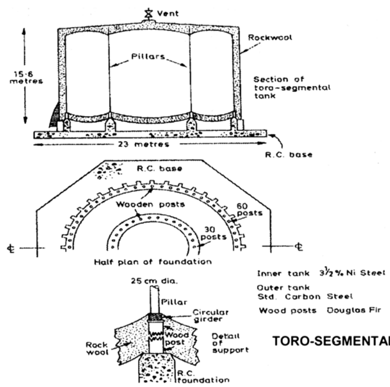
LNG technology has improved since the 1960s, developed partly from NASA's advancement.

D.1 The Cleveland fire

East Ohio Gas Company built the first commercial LNG plant for peakshaving at their gas manufacturing plant bordering a residential area. On 24 October 1944, there were a series of gas deflagrations and a fire that largely destroyed the plant and portions of an adjoining residential area causing the death of 133 people. The unexpected severity of this disaster raised concerns that similar conditions could cause a similar disaster in other communities.

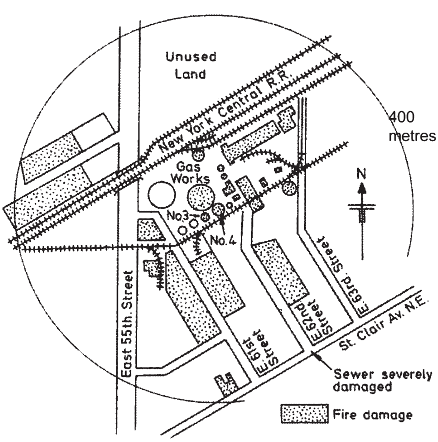
Layout and tanks

The original facility was constructed in 1940 and included liquefaction equipment and three spherical storage tanks of 100,000 gallons (380,000 litres) of liquid capacity. The increased gas demand led to the construction of a fourth storage tank with a larger capacity and a different design. This tank had a capacity of 160,000 cubic feet (4,530m^3) of LNG and was designed as a vertical, cylindrical tank with a 'toro-segmental' floor and roof.



TORO-SEGMENTAL TANK

Both the three spherical tanks and the fourth tank were fabricated from 3-1/2% nickel steel. The first three tanks were put into service without incident. Early in the initial filling of the fourth tank in June 1943, a crack occurred in the inner tank bottom. This crack was repaired and the tank was cooled down slowly and put in service. Sometime after the leak episode from tank #4, provision was made to control potential leakage from the tank. It consisted of concrete dikes around the spherical tanks and a dike around the cylindrical tank.



The incident

On 20 October 1944, the #4 cylindrical tank failed with a large release from the vertical portion of the tank, followed by an apparent collapse of the tank. The tank height was 15m (51 feet) as compared with a 2m (7 foot) high dike located just 2.6m (8 feet 6 inches) from the outer wall of the tank. The impounding volume inside the dike was less than 53% of the tank contents. Thus, either dike overflow, trajectory over the top, or both allowed the LNG to escape outside the dikes and flow freely according to the slope of the terrain.

The vapour cloud extended into the residential area and some of the LNG entered into the sewer system.

Results of explosions in the public sewer system. Absence of fire damage suggests RPTs in the sewers. The vehicle is a fire truck which had been responding to the incident.

There were numerous ignition sources within 60m (200 feet) of the tank and ignition of the vapour cloud occurred almost immediately. The elevated legs of the spherical tank adjacent to the cylindrical tank failed about 20 minutes after the failure of the cylindrical tank. This resulted in a muffled sound indicating the ignition of a large amount of gas. The two remaining spherical tanks were damaged, but remained intact.

The result of the disaster was that most buildings within 90m (300 feet) of the cylindrical tank were destroyed with 133 known deaths. Eighty-two dwellings were destroyed. Significant explosions were limited to confined spaces within the sewer systems as far as five blocks from the plant.

Causes

The five primary causes of the failure and ensuing disaster can be evaluated against current code requirements and are presented below:

- *Inappropriate material for the inner tank*. The 3-1/2% nickel steel at low temperatures. Present codes require specific material properties, testing of both materials and weld procedures and radiographic examination.
- *The impounding volume was less than the tank contents.* The impoundment requirements for LNG storage are now not less than 110% to 150% of tank contents.
- *The LNG release probably passed over the impounding dikes.* Current regulations require a dike height which will prevent an elevated release from the tank passing over the dike.
- *The vapour cloud from the release entered the adjacent residential area.* Current codes require that a plant be sited such that there is essentially no public exposure within the calculated maximum excursion of a gas concentration equivalent to one half of the lower flammable limit.
- *There were many secondary fires and injuries due to the radiant heat of the burning LNG*. Current regulations require containment of the LNG within the impoundment area. Siting requirements set the maximum thermal radiation allowable assuming a pool fire of the entire tank contents.

Secondary contributing factors may have been:

- *There may have been an outer tank bottom failure due to low temperature embrittlement which contributed to the inner tank failure.* Current codes require protection of the outer tank from low temperatures including heating of the outer tank floor.

In summary, had the Cleveland tank been built to current codes, it is highly improbable that there would have been a failure. LNG tanks constructed of 9% nickel steel have never, in their 35-year history, had a crack failure. Current siting requirements would have prevented siting an LNG plant that would expose the public to the vapour cloud hazard or the thermal radiation hazard. Given current technology and regulations, a repeat of the Cleveland accident is an unlikely event.

D.2 Staten Island, New York, February 1973

In February 1973, an industrial incident unrelated to the presence of LNG occurred at the Texas Eastern Transmission Company peakshaving facility on Staten Island.

The incident

In February 1972, the operators, suspecting a possible leak in the tank, took the facility out of service. Once the LNG tank was emptied, tears were found in the mylar (polyurethane) lining. During the repairs the mylar liner was ignited. The resulting fire caused the temperature in the tank to rise, generating enough pressure to dislodge a 150 mm (6 inch) thick concrete roof, which then fell on the workers in the tank, killing 40 people.

The Fire Department of the City of New York report of July 1973 determined that the incident was clearly a construction incident and not an 'LNG incident'. In 1998, the New York Planning Board, while re-evaluating a moratorium on LNG facilities, concluded the following: 'The government regulations and industry operating practices now in place would prevent a replication of this incident. The fire involved combustible construction materials and a tank design that are now prohibited. Although the exact causes may never be known, it is certain that LNG was not involved in the incident and the surrounding areas outside the facility were not exposed to risk'.

D.3 Cove Point, Maryland, October 1979

In October 1979, an explosion occurred within an electrical substation at the Cove Point, MD receiving terminal. LNG leaked through an inadequately tightened LNG pump electrical penetration seal, vaporized, passed through 60m (200 feet) of underground electrical conduit, and entered the substation. Since natural gas was never expected in this building, there were no gas detectors installed. The normal arcing contacts of a circuit breaker ignited the natural gas-air mixture, resulting in an explosion. The explosion killed one operator in the building, seriously injured a second and caused about $3 million (£1.5 million) in damages.

This was an isolated incident caused by a very specific set of circumstances. The National Transportation Safety Board found that the Cove Point Terminal was designed and constructed in conformance with all appropriate regulations and codes. However, as a result of this incident, three major design code changes were made at the Cove Point facility prior to reopening. Today, those changes are now applicable industry-wide.

Given all the safety and security measures provided in the LNG value chain, there is a low probability of a serious incident. However the consequences of failure at land-based terminals, as with other energy facilities, can be quite large if proper safety precautions and protections are not employed.

The small number of safety incidents that have occurred demonstrates the outstanding safety of the LNG industry. A table at the end of this appendix lists other LNG-related incidents, along with some of the critical improvements that have been made.

D.4 LNG incidents historical table

Incident Date	Ship/ Facility Name	Location	Ship Status	Injuries/ Fatalities	Ship/ Property Damage	LNG Spill/ Release	Comment
1944	East Ohio Gas LNG Tank	Cleveland	NA	128 deaths	NA	NA	Tank failure and no earthern berm. Vapour cloud formed and filled the surrounding streets and storm sewer system. Natural gas in the vaporizing LNG pool ignited.
1965		Canvey Island, UK	A transfer operation	1 seriously burned		Yes	
1965	Jules Vernet		Loading	No	Yes	Yes	Overfilling. Tank cover and deck fractures.
1965	Methane Princes	Disconnecting after discharge	No	Yes	Yes		Valve leakage. Deck fractures.
1971	LNG ship Esso Brega, La Spezia LNG Import Terminal	Italy	Unloading LNG into the storage tank	NA	NA	Yes	First documented LNG Rollover incident. Tank developed a sudden increase in pressure. LNG vapor discharged from the tank safety valves and vents. Tank roof slightly damaged. No ignition
1973	Texas Eastern Transmission, LNG Tank	Staten Island	NA	40 killed	No	No	Industrial incident unrelated to presence of LNG. During the repairs, vapours associated with the cleaning process apparently ignited the mylar liner. Fire caused temperature in the tank to rise, generating enough pressure to dislodge a 6-inch (150 mm) thick concrete roof, which then fell on the workers in the tank.

Incident Date	Ship/ Facility Name	Location	Ship Status	Injuries/ Fatalities	Ship/ Property Damage	LNG Spill/ Release	Comment
1973		Canvey Island, UK	NA	No	Yes	Yes	Glass breakage. Small amount of LNG spilled upon puddle of rainwater, and the resulting flameless vapour explosion, called a rapid phase transition (RPT), caused the loud “booms.” No injuries resulted.
1974	Massachusetts		Loading	No	Yes	Yes	Valve leakage. Deck fractures.
1974	Methane Progress		In port	No	Yes	No	Touched bottom at Arzew.
1975	Philadelphia Gas Works		NA	No	Yes	NA	Not caused by LNG. An isopentane intermediate heat transfer fluid leak caught fire and burned the entire vaporizer area.
1977	Arzew	Algeria	NA	1 worker frozen to death	NA	Yes	Aluminum valve failure on contact with cryogenic temperatures. Wrong aluminum alloy on replacement valve. LNG released, but no vapour ignition.
1977	LNG Aquarius		Loading	No	No	Yes	Tank overfilled.
1979	Columbia Gas LNG Terminal	Cove Point, Maryland	NA	1 killed 1 injured seriously	Yes	Yes	An explosion occurred within an electrical substation. LNG leaked through LNG pump electrical penetration seal, vaporized, passed through 200 feet (60 m) of underground electrical conduit, and entered the substation. Since natural gas was never expected in this building, there were no gas detectors installed in the building. The normal arcing contacts of a circuit breaker ignited the natural gas-air mixture, resulting in an explosion.
1979	Mostefa Ben-Boulaied Ship	?	Unloading	No	Yes	Yes	Valve leakage. Deck fractures.
1979	Pollenger Ship	?	Unloading	No	Yes	Yes	Valve leakage. Tank cover plate fractures.
1979	El Paso Paul Kayser Ship		At sea	No	Yes	No	Stranded. Severe damage to bottom, ballast tanks, motors water damaged, bottom of containment system set up.
1980	LNG Libra		At sea	No	Yes	No	Shaft moved against rudder. Tail shaft fractured.
1980	LNG Taurus		In port	No	Yes	No	Standed. Ballast tank all flooded and listing. Extensive bottom damage.
1984	Melrose		At sea	No	Yes	No	Fire in engine room. No structural damage sustained-limited to engine room.
1985	Gradinia		In port	No	Not reported	No	Steering gear failure. No details of damage reported.
1985	Isabella		Unloading	No	Yes	Yes	Cargo valve failure. Cargo overflow, Deck fractures.

The El Paso Paul Kayser LNG tanker listed in the table, showing the damage after grounding at full speed. Due to the double hull arrangement, there was no loss of containment.

Incident Date	Ship/ Facility Name	Location	Ship Status	Injuries/ Fatalities	Ship/ Property Damage	LNG Spill/ Release	Comment
1989	Teilier		Loading	No	Yes	Yes	Broke moorings. Hull and Deck fractures.
1990	Bachir Chihani		At sea	No	Yes	No	Sustained structural cracks allegedly caused by stressing and fatigue in inner hull.
1993	Indonesian Ilquefaction facility	Indonesia	NA	No	NA	NA	LNG leak from open run-down line during a pipe modification project. LNG entered an under ground concrete storm sewer system and underwent a rapid vapour expansion that over pressured and ruptured the sewer pipes. Storm sewer system substantially damaged.
2002	LNG ship Norman Lady	East of the Strait of Gibraltar	At sea	No	Yes	No	Collision with a U.S. Navy nuclear-powered attack submarine, the U.S.S Oklahoma City. In ballast condition. Ship suffered a leakage of seawater into the double bottom drytank area.

Appendix E: LNG road tanker incidents

E.1 Nevada, USA

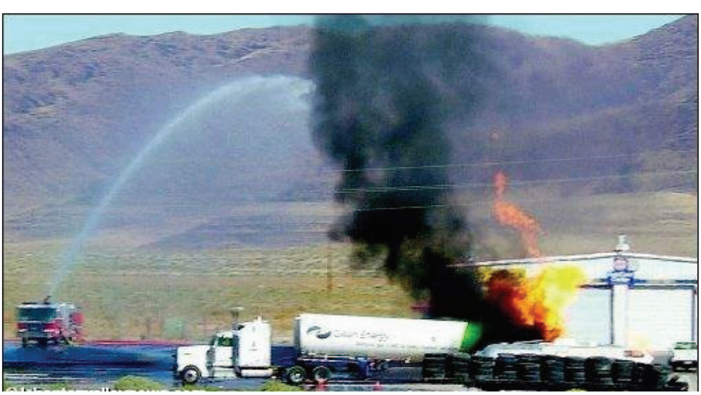
In Fernley, Lyon County, Nevada, in September 2005, an LNG road tanker containing 10,000 US gallons (38,000 litres) of LNG developed a leak in what appeared to be a rear valve leak or valve shear.

It is understood that a number of issues contributed to this incident. The tanker was parked in a non-hazardous goods area when the leak developed from the rear valving area. It appears the driver did not shut off the emergency shut-off lever located on either side of the truck. Responders initially stood near to the liquid as they did not have LNG specific hazard awareness or response experience. The vapour from the release was reportedly ignited by a fire truck engine and flashed to source. The lack of knowledge and information on LNG incidents led to the fire chief declaring a one-mile (1.6 km) exclusion zone and requiring evacuations within that area.

The incident began at approximately 07:30. An emergency response HAZMAT team was attempting to isolate the leak when ignition occurred. The tanker was in the parking area of a roadside motel and restaurant when the incident took place.

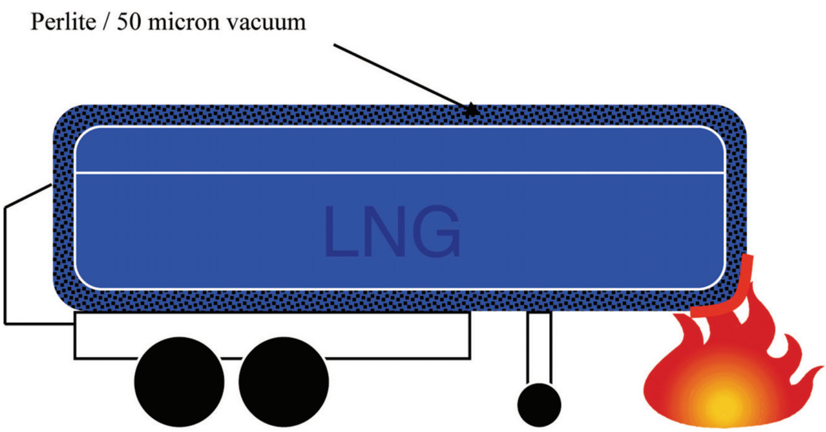
The surrounding area was evacuated to a distance of one mile and after initial cooling, all responders were pulled out. The fire continued to burn without escalation until after 15:00 the same day. Road and highway closures remained in force until 16:30.

The response strategy assumed by the fire chief was that an explosion could occur. No injuries were reported for this incident.



The design of US LNG road tankers has an inner and outer tank with a perlite insulation between the tanks as shown below. The inner tank is typically aluminium.

Not all countries follow the same design.



The table below indicates US LNG road tanker incident events during transportation activities.

US Highway Transportation Incidents (1971–2005)	
No LNG Spill or LNG Fire	8
LNG Leak with Fire	1
Vapour Leaks with No Fire	1
LNG Spills with No Fire	5
Fires Not Involving LNG	2
Tanker Rollover	11
Involved Fatalities (Non LNG)	1

E.2 Catalonia, Spain

The accident took place on 22 June 2002, at 13:30 p.m., on the C-44 road near Tivissa, Catalonia (Spain). A tanker containing natural gas lost control on a downhill section of the road, probably due to speeding.

It turned over, tipping onto its left side and finally came to a halt beside a sandy slope. Immediately, flames appeared between the cabin and the trailer, initially with practically no smoke.

One witness who was located initially at a distance of 70 m (230 ft) said that the initial flames were blue and very high (this was not confirmed by the other two witnesses). Moments later, the tyres started to burn, producing small explosions and black smoke. According to the witnesses, the flames then increased in size, becoming very large (see photograph taken approximately two minutes after the road accident).

The flames could be fed by the diesel oil from the truck tank or by the LNG (a broken pipe connecting the tank to the safety valve?) or, more probably, by both. The photograph shows the existence of white smoke, which could be vapour originated from a liquid release from the safety valve.

Approximately 20 minutes after the road accident, the tank exploded. There was a small explosion, then a strong hiss and then the large explosion.

Immediately after the explosion, the fire disappeared and a white cloud appeared. This ignited immediately giving rise to a fireball.

The driver died, and two persons located approximately 200 m (655 ft) away were injured (burned).

Tanker construction

The tanker, built 28 months earlier (AISI-304 stainless steel), was cylindrical, with a diameter of 2.33 m (7.6 ft) and an approximate length of 13.5 m (45 ft). It was made of stainless steel (4 mm (0.15”) thick at the wall and 6 mm (0.24”) thick at the ends). It had internal baffles (each one 7.5 m^3 (265 ft^3)) that were 3 mm (0.12”) thick.

It was protected with an expanded polyurethane external insulation (130 mm (5.1”) thick, self-extinguishing, and covered by a 2 mm (0.08”) aluminium plate). It was designed for a working pressure of 7 bar (101.5 psi) , the hydraulic test being performed at 9.1 bar (132 psi) . With a volume of 56 m^3 (1,980 ft^3), 85% of it was filled with liquid (this implies approximately 47.6 m^3 (1,680 ft^3) of liquid and 8.4 m^3 (296 ft^3) of gas). The temperature of the LNG was slightly below −160° C (–265°F) and the pressure slightly below 1 bar (14.5 psi). There were five safety valves: two 1 in. (25 mm) valves set to 7 bar (101.5 psi) and one 3/4 in. (19 mm) valve set to 9 bar (131 psi), located at the top of the vessel (in the vapour zone); and two 1/2 in. (13 mm) valves set to 10 (145 psi) bar located on the unloading pipes (under the vessel); all these valves were connected to a discharge pipe located at the top of the vessel. There was no manhole.

The truck had a 0.5 m^3 (18 ft^3) aluminium diesel oil tank.

The existence of a first explosion, then a strong hiss and afterwards the large explosion, seems to confirm the two-step mode for the failure of the vessel–the formation of an initiating crack by thermal stress at a very hot location of the wall, arrested in a cooler and stronger zone (in the vapour zone, metal wall temperatures are extremely variable under the action of fire), followed by a discharge (probably two-phase flow); then, the restart of the crack due to further thermal stress at the crack tip originated by the cooling effect of the

The road tanker two minutes after the road accident and approximately 18 minutes before the explosion. The car was left by one of the witnesses who fled

The front end of the tanker post explosion.

The rear end of the tanker post explosion.

two-phase release through the crack, leading to the catastrophic failure of the vessel.

The effects of the road tanker explosion were overpressure, thermal radiation and missile ejection.

E.3 Wales, UK

During a journey in Wales, a fully loaded LNG road tanker rolled over at a roundabout near Aberystwyth, damaging street lighting before coming to rest on its side. The company concerned responded and were on scene after 45 minutes. The complete LNG load was safely transferred without any releases.

Appendix F: LNG ship pre-arrival checks

IMPORTANT: check latest version in OCIMF/ISGOTT/SIGTTO documents and refer to these for more details

Pre-arrival checks–terminal (receiving)

Note: To be carried out within 48 hours of ship's arrival		**Sat**	**Unsat**
1.1	Terminal Operations/Emergency Procedures Manual located at dockside transfer control areas.		
1.2	Terminal marine transfer area adequately lighted.		
1.3	Minimum of two (2) portable gas detectors (0–100% LEL methane) readily available at transfer area.		
1.4	Appropriate WARNING signs posted.		
1.5	No dangerous maintenance supplies stored in transfer area. One day supply permitted		
1.6	Cameras at transfer area operation correctly.		
1.7	Communications systems operational: Phone, Radios, Paging Systems and Hotline		
1.8	Safety, life saving equipment, fire monitors, equipment available.		
1.9	Ultraviolet (UV) sensors and other hazard detection systems, including alarms functioning correctly.		
1.10	Remote dry chemical control systems operable.		
1.11	Dry chemical nitrogen cylinders at proper pressure.		
1.l2	Fire suppression systems in active position in the Main Control Room.		

Note: To be carried out within 48 hours of ship's arrival		**Sat**	**Unsat**
1.13	Foam system in active position and operable. Last foam analysis date:		
1.14	Fire water system operable. Last test date:		
1.15	Transfer area fire monitors, hoses, fire pump discharge valves, etc. lined up and operable.		
1.16	Diesel powered fire pumps operable. Date of last test:		
1.17	Emergency electrical power generator operational. Date of last test:		
1.18	Loading arms over-slew shutdown and alarms operable. Date of last test:		
1.19	Loading arms over extension shutdown and alarms operable. Date of last test:		
1.20	Check ESD system.		
1.21	Operation of shore gangway.		
1.22	Check of mooring line tension monitoring system.		
1.23	Check of docking aid system.		
1.24	Operation of quick release hooks and mooring line capstans.		
1.25	Check of return gas blowers.		
1.26	Check of weather observation system.		
1.27	Check of liquid and vapour lines ESD valves closing time.		
1.28	Verification of return gas flare pilot.		
1.29	Notification of completion for ship's pre-arrival checks.		

Pre-arrival checks–LNG carrier

Note: To be carried out in various stages starting 48 hours prior to ship's arrival		Sat	Unsat
1.1	Confirm operation of the Custody Transfer Management System.		
1.2	Set up and test ship/shore ESD system.		
1.3	Test ESD system as applicable.		
1.4	Test independent 98.5% fill and 99% fill as applicable.		
1.5	Check operation of cargo valves including opening and closing times.		
1.6	Check or operate water curtain system per maintenance schedule.		
1.7	Check fixed and portable gas/O_2 metres.		
1.8	Check ballast system.		
1.9	Check all deck lighting.		
1.10	Test UHF/VHF and sound power communications.		
1.11	Dry chemical nitrogen cylinders at proper pressure.		
1.l2	Check and ready fire wires.		
1.13	Check operation of all mooring gear and prepare auxiliary equipment.		
1.14	Ballast ship to arrival condition.		
1.15	Check mooring line monitor.		
1.16	Check alignment/deployment (just prior arrival) of dry chemical system.		
1.17	Empty swimming pool.		
1.18	Check cargo system lineup including basket strainers.		
1.19	Check all manifold equipment.		
1.20	Check and gangway and pilot ladders including auxiliary equipment.		

Ship and terminal pre-loading or discharge meetings

Before the commencement of cargo transfer at either an LNG loading or receiving terminal a pre-cargo transfer meeting is held.

During the meeting the following should be discussed and agreed between both the LNG carrier and terminal:

- Agree when the hard arms and ESD cable can be brought aboard the LNG carrier and connected.
- Agree to primary and secondary communication means and verify that they are working.
- Method, if available, of providing the LNG carrier information concerning the mooring lines.
- Inerting and leak testing vapour and liquid hard arms.
- ESD tests from LNG carrier and the terminal.
- Opening custody transfer for the LNG carrier.
- Opening of the LNG carriers vapour valve.
- Cooling down of liquid hard arms and LNG carrier liquid arms.
- Rating up the LNG transfer and agreeing maximum rate of transfer.
- Rating up the vapour return between the LNG carrier and terminal.
- Periodic communication of the LNG transfer rate, tank pressures and other agreed information.
- Notice of rating down LNG transfer and the securing of transfer pumps until transfer is completed.
- Draining and purging of LNG hard arms.
- Closing custody transfer of the LNG carrier.
- Purging of the vapour hard arm.
- Disconnecting of LNG and vapour hard arms.
- Installing blinds on LNG carrier and terminal LNG and vapour connections.
- Manoeuvring of LNG and vapour hard arms to the stowed position.
- Unmooring of the LNG carrier.

In addition to the above, the LNG carrier and terminal will agree to actions to take in the case of an emergency or if conditions threaten the safe transfer of LNG.

A ship/shore safety checklist will also be completed during the pre-loading or discharge meeting. Where the terminal is unable to provide a checklist that meets the Society of International Gas Tanker and Terminal Operator (SIGTTO) standards the Ship/Shore safety checklist in Appendix G should be used.

Appendix G: LNG ship/shore safety checklist

IMPORTANT: check latest version in OCIMF/ISGOTT/SIGTTO documents and refer to these for more details

<u>Ship/Shore Safety Checklist</u>

Ship's name:

Port:____________________ Berth: ___________

Date of arrival: ________ Time all fast: ________

INSTRUCTIONS FOR COMPLETION

The safety of operations requires that all questions should be answered affirmatively by clearly ticking the appropriate box. If an affirmative answer is not possible, the reason should be given and agreement reached upon appropriate precautions to be taken between the ship and the terminal. Where any question is considered not to be applicable, then a note to that effect should be inserted in the remarks column.

A box in the columns 'Ship' and 'Terminal' indicates that checks should be carried out by the party concerned.

The presence of the letters A, P or R in the column 'Code' indicates the following:

A – any procedures and agreements should be in writing in the remarks column of this checklist or other mutually acceptable form. In either case, the signature of both parties should be required.

P – in the case of a negative answer, the operation should not be carried out without the permission of the Port Authority.

R – indicates items to be rechecked at intervals not exceeding that agreed in the declaration.

General	Ship	Terminal	Code	Remarks
1. Is the ship securely moored?			R	Stop cargo at: _____ kts wind vel. Disconnect at: _____ kts wind vel. Unberth at: _______ kts wind vel.
2. Are emergency towing off wires correctly positioned?			R	
3. Is there safe access between ship and shore?			R	
4. Is the ship ready to move under its' own power?			PR	
5. Is there an effective deck watch in attendance on board and adequate supervision on the terminal and on the ship?			R	
6. Is the agreed ship/ shore communication system operative?			AR	
7. Has the emergency signal to be used by the ship and shore been explained and understood?			A	
8. Have the procedures for cargo, bunker and ballast handling been agreed?			AR	
9. Have the hazards associated with LNG handling been identified and understood and the MSDS sheet been posted?				

General	Ship	Terminal	Code	Remarks
10. Has the emergency shutdown procedure been understood?			A	
11. Are cargo and bunker hoses/arms in good condition, properly rigged and appropriate for the service intended?				
12. Are scuppers effectively plugged and drip trays in position, both onboard and ashore?			R	
13. Are unused cargo and bunker connections properly secured with blank flanges fully bolted?				
14. Are all cargo and bunker tank lids closed?				
15. Are hand torches of an approved type?				
16. Are portable radio transceivers of an approved type?				
17. Are all mobile phones/pagers switched off when on deck?				
18. Are electric cables to portable electrical equipment disconnected from power?				
19. Are the ship's main radio transmitter aerials earthed, AIS and radars switched off?				

General	Ship	Terminal	Code	Remarks
20. Are all external doors and ports in the accommodation closed?			R	
21. Is the air-conditioning set to re-circulation?				
22. Are the requirements for the use of galley equipment and cooking appliances being observed?			R	
23. Are smoking regulations being observed?			R	
24. Are naked light regulations being observed?			R	
25. Is there provision for an emergency escape?				
26. Are sufficient personnel onboard and ashore to deal with an emergency?			R	
27. Are ship emergency fire control plans located externally?				
28. Are adequate insulating means in place in the ship/shore connection?				
29. Is the water spray system ready for use?				
30. Are fire hoses and fire-fighting equipment on board and ashore				

General	Ship	Terminal	Code	Remarks
positioned and ready for immediate use?			R	
31. Is sufficient suitable protective equipment (including SCBA), and protective clothing ready for immediate use?				
32. Is the fixed and portable gas detection equipment calibrated and in good order?				
33. Are cargo system gauges and alarms correctly set and in good order?				
34. Are all remote control valves in good working order?				
35. Are the required cargo pumps and compressors in good order, and have maximum working pressures been agreed between ship and shore?			A	
36. Are cargo tanks protected against inadvertent overfilling at all times while any cargo operations are in progress?				

General	Ship	Terminal	Code	Remarks
37. Are cargo tank relief valves set correctly and actual relief settings clearly and visibly displayed?				
38. Has a vapour return line been connected?				
39. If a vapour return line is connected, have operating parametres been agreed?				Return gas pressure. . . . .
40. Are the hold/inter barrier spaces properly inerted or filled with dry air as required?				
41. Is the compressor room properly ventilated; the electrical motor room properly pressurized and is the alarm system working?				
42. Are emergency shutdown systems working properly?				
43. Does the shore know the closing rate of the ship's automatic valves; does the ship have similar details of the shore system?			A	Ship. . . . . Shore. . . . .

Declaration

We the undersigned, have checked, where appropriate jointly, the items on this checklist and have satisfied ourselves that the entries we have made are correct to the best of our knowledge.

We have also made arrangements to carry out the repetitive checks as necessary and agreed that those items with the letter 'R' in the column 'Code' should be re-checked at intervals not exceeding . . .. hours (not to exceed 6 hours).

For Ship	For Shore
Name:	Name:
Rank:	Position:
Signature:	Signature:
Date: Time:	Date: Time:

Revalidation

We have conducted a routine inspection and can confirm the repeat questions in the checklist continue to be answered in the affirmative.

For Ship		For Terminal		Date	Time
Name	Signature	Name	Signature		

Appendix H: Repeat checks during cargo operations

IMPORTANT: check latest version in OCIMF/ISGOTT/SIGTTO documents and refer to these for more details

TIME										
1. Is the ship securely moored?										
2. Are emergency towing off wires correctly positioned?										
3. Is there safe access between ship and shore?										
4. Is the ship ready to move under its' own power?										
5. Is there an effective deck watch in attendance on board and adequate supervision on the terminal and on the ship?										
6. Is the agreed ship/shore communication system operative?										

7. Have the procedures for cargo, bunker and ballast handling been agreed?										
8. Are scuppers effectively plugged and drip trays in position, both onboard and ashore?										
9. Are all external doors and ports in the accommodation closed?										
10. Are the requirements for the use of galley equipment and cooking appliances being observed?										
11. Are smoking regulations being observed?										
12. Are naked light regulations being observed?										
13. Are sufficient personnel onboard and ashore to deal with an emergency?										
14. Are fire hoses and fire-fighting equipment on board and ashore positioned and ready for immediate use?										