Rollover in LNG Storage Tanks

Summary Report by the GIIGNL Technical Study Group on the Behaviour of LNG in Storage

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Summary

LNG "rollover" refers to the rapid release of LNG vapours from a storage tank caused by stratification. The potential for rollover arises when two separate layers of different densities (due to different LNG compositions) exist in a tank. In the top layer, liquid warms up due to heat leakage into the tank, rises up to the surface, where it evaporates. Thus light gases are preferentially evaporated and the liquid in the upper layer becomes denser. This phenomenon is called "weathering". In the bottom layer, the warmed liquid rises to the interface by free convection but does not evaporate due to the hydrostatic head exerted by the top layer. Thus the lower layer becomes warmer and less dense. As the density of two layers approach each other, the two layers mix rapidly, and the lower layer which has been superheated gives off large amount of vapour as it rises to the surface of the tank.

The main hazard arising out of a rollover accident is the rapid release of large amounts of vapour leading to potential over-pressurization of the tank. It is also possible that the tank relief system may not be able to handle the rapid boil-off rates, and as a result the storage tank will fail leading to the rapid release of large amounts of LNG to the atmosphere. It is important to emphasise the difference between stratification and rollover. Stratification is the phenomenon of stored LNG forming distinctive cells which is driven by density differences and can be manipulated for boil-off gas optimisation; rollover is the rapid release of boil-off gas in an uncontrolled event which can have safety implications. LNG rollover received considerable attention following a major unexpected venting incident at an LNG receiving terminal at La Spezia, Italy in 1971.

Stratification is managed by use of measurement devices upon the LNG storage tanks, of which, the types of instrumentation required are stipulated within design codes. Advances of rollover prediction models have also enabled operators to prevent and make informed decisions for the management of stratification within LNG storage tanks.

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Preference to First Edition

In presenting the second edition of Rollover in LNG Storage Tanks, it has been our intention to cover what we believe to be the important developments within the LNG industry for the management of stratification of stored LNG leading to rollover events. Significant advances have been made in areas covering, design, instrumentation, operating knowledge, training operators on LNG behaviour and the use of modelling software to prevent and in some cases instigate stratification to seek operating efficiencies. The reader will find that this edition is written with one eye on the future as the LNG industry at the time of writing is continuing to develop at a fast rate, with new processes being introduced. The principles of management stratification for these new processes are as yet not thoroughly developed.

Organisation of the Study

The composition of the Task Force which collected the information contained in this report and met regularly in the process of the evaluation of the information is as follows:

Simon Culkin (Chairman)	National Grid Grain LNG
Jason Shirley (Technical Co-ordinator)	National Grid Grain LNG
Abrar Bajwa (Technical Assistant)	National Grid Grain LNG
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The authors acknowledge with thanks the assistance given by companies and individuals in providing suggestions and for additions that they have felt to be important along with illustrations and data for this edition and giving their permission for reproduction. Everyone was most helpful and some firms went to considerable trouble to provide exactly what was required. We are extremely grateful to them all.

This report was based on the first edition and was developed in reference to numerous reports and other sources of information produced by the members of the Task Force. The report was written by Dr Jason Shirley, Technical Co-ordinator for the Task Force.

Contents

1. Introduction

At the 2012 Technical Study Group meeting of GIIGNL member companies in Osaka, it was decided to revise the "Rollover in LNG Storage Tanks" study document. The original document was published in 1983 and was a reactive response following the first significant rollover incident widely reported in the history of the LNG (Liquefied Natural Gas) industry that occurred in La Spezia, Italy, 1971. In the intervening 31 years from the publication of the original study, there have been considerable developments in the study of the behaviour of LNG in storage tanks and the whole subject has undergone a number of changes. A Task Force was formed with the aim of updating the original study to reflect the current industry position whilst retaining a similar structure and physicochemical study findings provided by the original authors. This report presents a summary of the Task Forces assessment of the current state of knowledge of rollover and incidents of excessive vapour evolution in LNG storage tanks.

The remainder of this section gives a brief introduction to rollover and a description of how the study was carried out. Following sections deal with the fluid dynamics and thermodynamics of LNG in storage tanks (Section 2), rollover incident case studies (Section 3), measurement and prevention of stratification (Sections 4 & 5) and prediction modelling which is developing areas of study within this subject area (Sections 6). The report concludes with a general bibliography.

1.1 The Occurrence of Rollover

It is possible in LNG storage tanks for two stable stratified layers or cells to be established, as a result of inadequate mixing of either fresh "light" LNG with a denser heel (a process typical of a Peak Shave storage plant), or by unloading LNG of different densities into a storage tank (a process that may occur within an import LNG Terminal). Importation terminals receive cargos from many parts of the world and are delivered with varying densities and temperatures.

Within the stratified cells, the liquid density is uniform but the bottom cell is composed of liquid that is denser than the liquid in the cell above. Subsequently, if a layering condition is allowed to persist over a period of time, the energy in the lower layer will build up due to heat leak into tank. The boil-off gas from the bottom layer is suppressed due to the hydrostatic pressure impressed on it from the upper layer. Heat leak into the tank will gradually increase the bottom layer temperature and therefore decrease its density. As the densities of the two layers approach equilibrium, the potential for a rollover event increases. As the two layers mix, the boil-off gas that was retained by the bottom layer will be released, which can result in a high rate of vapour generation. This rate can be significantly greater than the tank's normal boil-off rate and in a few instances the pressure rise in the tank has been sufficient to cause pressure relief valves to lift.

This phenomenon is known as 'rollover', meaning the layers roll over or reverse. Technically, this is not exactly what happens, but this terminology has become quite established across the industry. Depending on the severity of the event, the effects can range from simply a small pressure rise in the tank for a short period of time to a significant loss of product over an extended period of time through the tank's relief valves. Although, very unlikely, in the event of a serious rollover the potential also exists of physical damage to the tank due to over pressurisation.

LNG rollover phenomena received considerable attention following a major unexpected venting incident at an LNG receiving terminal at La Spezia, Italy in 1971. Therefore precautions must be taken to manage the potential for stratification to ensure that it doesn't lead to a rollover event. Detection and mitigation techniques are employed to identify when conditions exist for a possible rollover event and to impede the occurrence of such an event.

1. Introduction

1.2 Advances in the Industry

The main advances in the LNG industry that have affected the management of stratification for the prevention of rollover occurrence have been in both the design and technology deployed on LNG terminals and ships as well as the trading patterns.

The growth of the LNG trade worldwide has led to an increase in differing LNG qualities being available in the world market. Thus, import terminals are now faced with the need to handle these differing LNG qualities according to the source.

LNG demand in the world has been increasing and expected from current 170 million tons per annum to 400 million tons per annum in mid 2020's. In conjunction with the growing demand, many new LNG receiving terminals will be constructed all over the world in a variety of circumstances. The global network of terminals is growing in the US, South America, Europe, China and India because of the growing demand for LNG as a cleaner energy source.

A change in LNG trading and shipping patterns can have a direct effect on the potential of rollover in storage tanks. As market demand increases and new supply sources emerge, importers are widening their range of LNG quality. The evolving spot market has increased the potential of commingling lean and rich cargo in the same storage tank.

The growth phase that the LNG industry is currently experiencing means that there is a wide variety of LNG in the supply chain and there are more operators on both supply and demand sides. There have been developments within the size of ships and new shipping patterns such as partial offload and reload.

A current area of interest is within the development of a prediction tool for preventing rollover within Floating LNG Production, Storage and Off-loading (FPSO) plants. These floating production plants present challenges for the use of current prediction tools due to the sloshing motion of the ships that is not needed for consideration of shore based LNG storage tanks. Also, the geometry of ships tanks differs from the more regular cylindrical shore based tanks particularly for the Moss style spherical tanks. Tank 1 membrane style tanks (located at the ship's bow end) tend to be a more irregular shape. Floating tanks are also being equipped with bottom fill only to reduce the boil-off gas generated during filling. This design limitation reduces the operational flexibility for management of stratification. There is a potential for rollover on FPSO ships as rollover events have occurred on convention LNG cargo ships. A case study of rollover on an LNG cargo ship is presented in Section 3.

The expanding market for LNG as a fuel will see LNG being utilised in more applications such as road tankers, satellite stations and bunkering stations (refer to the GIIGNL Retail Handbook for further reading). The management of the physicochemical properties of LNG will have to be considered within all of these developments to ensure that potentially hazardous events such as rollover are prevented.

1.3 Organisation of the Study

The study was carried out by leading expert representatives from eight Member Companies of GIIGNL.

Data was collated by questionnaires from Technical Study Group (TSG) members, other GIIGNL member companies and a number of companies with peak shaving operations that were known to have or thought to have an interest in rollover. Additional important data came from the published literature and directly from the GIIGNL database and other gas companies. Experts from the wider LNG industry contributed on specific subject areas.

1. Introduction

In order to spread the workload and to utilise specific expertise within individual companies in the best way, the subject was split into five topics. Eight Technical Study Group member companies took responsibility for devising questionnaires and for the analysis of data as follows:

SECTION 1	Introduction
SECTION 2	Rollover Phenomenon
SECTION 3	Rollover Incidents
SECTION 4	Measurement of Stratification
SECTION 5	LNG Stock Management
SECTION 6	Rollover Prediction Models

Disclaimer: The purpose of this document is to serve as a reference manual to assist readers to understand the procedures and equipment available to and used by the members of GIIGNL to manage stratification and prevent rollover in LNG terminals. It is neither a standard nor a specification and should be viewed as a summary of observations within the industry.

This document is not intended to provide the reader with the detailed occurrence of LNG stratification and rollover as such, but sets out the practical issues and requirements to guide and facilitate a skilled operator team to work out a suitable procedure for management of stratification and prevention of rollover.

This rollover study document has included commercially available software as part of the summary of the LNG prediction models that are being used by LNG operators. It was important to include reference to the different types of approaches for prediction models as this has been a significant area of development in the field of research for LNG stratification and rollover. GIIGNL have presented a balanced summary of the models that are in use by members of the Task Force. It is not GIIGNL's intention to promote commercial products and the group recognises that other products exist on the market. Readers should ensure that they are in possession of the latest information, standards and specifications for any procedures and equipment they intend to employ.

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Three preliminary teleconferences were conducted to initiate the Task Force and three full meetings were held with the members of the group in London, Paris and Gujarat, India in 2012. An update of the Task Force's progress was provided at the GIIGNL TSG meetings in Hammerfest and Dunkirk in 2013. The Task Force met for the final time in Paris 2013. The final document was presented at the 2014 TSG meeting in Boston.

In an attempt to understand the frequency of the occurrence of rollover incidents, a survey form was distributed amongst the member companies of GIIGNL. The results from the survey were intended to shape the discussion points within this document as to whether the rollover phenomenon is well understood and sufficiently managed within the industry. The questionnaire was sent out to 25 companies, of which there were 15 responses.

It is recognised that commercial and contractual issues have presented challenges with supply of information to the Task Force for rollover incidents. This resulted in a very limited capture of new data from the survey. Therefore, the data in this study has been supplemented with information from the GIIGNL incident database, commercial companies who work with LNG related products and literature in the public domain.

2. Rollover Phenomenon

LNG is a multi-component naturally occurring mixture of differing quantities of hydrocarbons (alkanes mostly methane CH_4 but also containing smaller concentrations of ethane C_2H_6, propane C_3H_8 and butane C_4H_{10}) and nitrogen (N_2). The LNG is stored in bulk in large storage tanks at a gauge pressure of some 0.10 to 0.24 bar and a temperature of approximately – 160°C. The tanks are insulated to reduce heat in-leak but heat is still transferred from the environment to the LNG in the tank. As a result of this heat in-leak, evaporation takes place of the more volatile components (N_2 and CH_4). This process is known as "weathering". Normally, weathering is a fairly slow process. Typically, an LNG tank will lose about 0.05% of its contents per day in boil-off gas to absorb the heat input and keep the remaining liquid cold. The weathering process therefore causes the composition of LNG to evolve over a period of time thus altering the density of the LNG. Generally, LNG of different densities can form separate layers within a storage tank. This layering is referred to as stratification and can also be formed during filling an LNG tank with LNG of different densities (commonly referred to within the industry as "light" and "heavy" LNG). The potential for rollover arises when two separate layers of different densities exist in a tank. This study will summarise the occurrence of stratification leading to rollover.

2.1 Equilibrium Conditions and the Surface Layer

The evaporation that occurs in an LNG tank is commonly referred to as "boil-off gas" (BOG). In this document the term "vapour evolution rate" is preferred to the term "boil-off rate" because the liquid does not normally boil in a commercial LNG tank. The term boil-off and boil-off rate are strictly applicable only when the liquid is boiling by the heat transfer process of nucleate boiling. In the majority of storage situations, there is only evaporation from the surface of the liquid and there is no boiling, then the term "evaporation rate" is then the correct terminology to use. However, boil-off is commonly used to describe all liquid evaporation and is frequently used in the industry. The gradual loss of methane by preferential evaporation causes the tank stock to increase in density as the concentration of C_2+ remaining in the tank increases. This weathering process is particularly important if the heat leak from the walls of the tank is large as in the case of some in-ground tanks or if the storage period is long as in the case of peak-shaving installations. Heat in-leak is also significant for LNG re-gasification terminals as the pipe work external from the tank has to be kept cold, particularly the LNG unloading lines from the jetty to the tanks. Large volumes of BOG are attributed to this form of heat in-leak which is evolved from the LNG upon returning to the tanks during LNG recirculation.

The heat input to the liquid from the floor and walls of the tank is absorbed and convected to the liquid surface where evaporation takes place. A free-convective circulation is set up with a (mainly turbulent) boundary-layer of slightly warm and less-dense liquid moving upwards close to the tank walls. Warmed liquid reaching the surface cools by evaporation, becomes more dense than the liquid surrounding it, and returns to the tank bottom as a central plug flow. Figure 2.1 shows the circulation, which has been observed in the laboratory (1, 2) and which accounts for the small (1 K or less) temperature differences usually found in LNG in commercial storage tanks (3). Estimates of the temperature difference across the wall boundary layer based on extrapolations of a turbulent flow correlation equation (4) give 0.05 K and 0.17 K for typical 50,000 m^3 tanks with losses or 0.03% and 0.06% of contents per day respectively.

2. Rollover Phenomenon

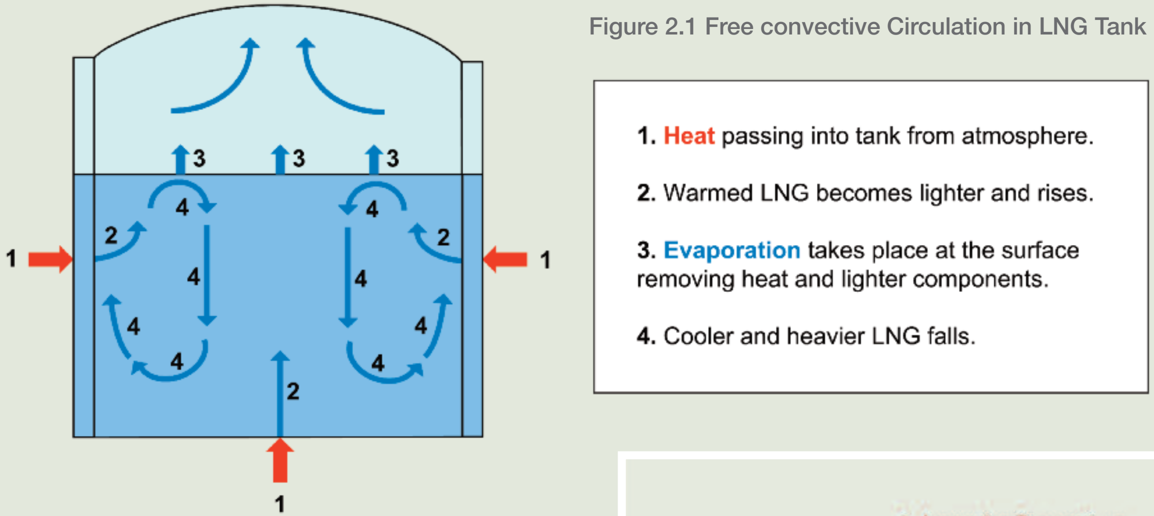


Figure 2.1 Free convective Circulation in LNG Tank

Several studies (5, 6, 7 and 8) have shown that a surface layer that is slightly cooler than the bulk liquid exists under these conditions. This surface layer is frequently called the Hashemi-Wesson layer. By adapting a well-known correlation equation for free convection from horizontal surfaces, Hashemi and Wesson arrived at an equation which can be used to show that the temperature difference in the layer depends on the mass flux (the rate of mass evaporation through unit surface area), i.e.

$$\dot{m} = 0.00127\,\Delta T_S^{\frac{4}{3}} \qquad (2.1)$$

Where $\dot{m}$ is the mass flux in kg/m²s and $\Delta T_S^{4/3}$ is the temperature difference across the layer in K. The liquid surface is effectively at the saturation temperature, T_S, corresponding to the pressure in the vapour space above (for its particular composition) and the bulk of the liquid is at an almost constant temperature warmer by an amount given by equation (2.1). For typical 50,000 m³ LNG tanks with total losses of 0.03% and 0.06% of contents per day, Equation (2.1) gives ΔT_S equal to 0.1 K and 0.15 K respectively. Small temperature differences must exist in the bulk liquid away from the boundary layer and the surface layer in order to maintain the free-convective circulation, but these can be ignored in a simple model.

Studies have shown (7) that there is a nearly linear variation of temperature in the surface layer. These studies were with liquid nitrogen but similar effects are likely with LNG. Figure 2.2 shows a typical (time-smoothed) vertical temperature profile in the liquid and vapour.

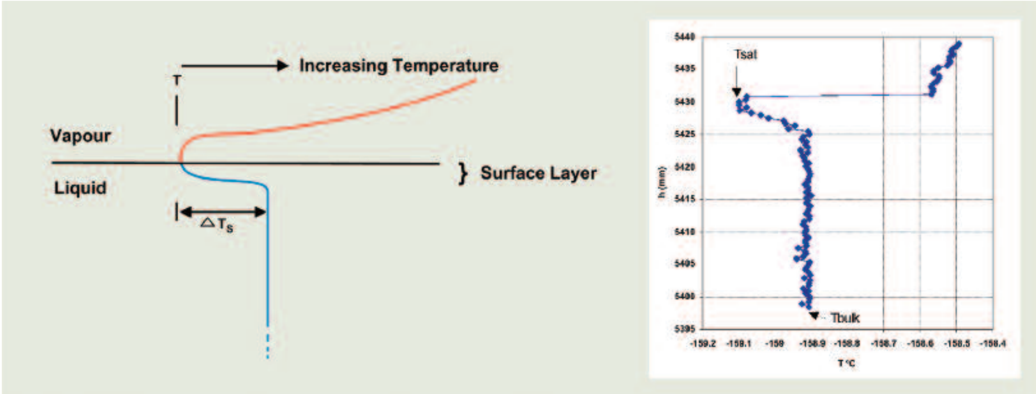


Figure 2.2 Typical temperature profile near liquid surface combined with experimental data from GDF Suez test in 500m³ pilot tank

Random temperature variations in the liquid which are not shown in this smoothed profile occur, probably due to turbulence in the flow. Above the liquid surface there is a region of approximately uniform temperature corresponding to a turbulent vapour layer, and above this the vapour temperature increases rapidly with the distance (8).

2.2 Effect of Disturbing the Equilibrium

Under normal storage conditions two types of disturbance occur to affect the vapour-evolution rate, pressure changes and physical disturbance of the surface layer.

2.2.1 Pressure Changes

Under certain operational conditions changes in barometric pressure are reflected as changes in the absolute pressure in the vapour space of a storage tank. At some installations this absolute pressure also depends on the number and capacity of vapour compressors in operation.

A fall in absolute pressure above the liquid surface causes the vapour-evolution rate to increase: a rise in absolute pressure causes the rate to decrease. Figures 2.3 (a) and 2.3 (b) show the results of a historic experiment that serves to demonstrate the effects on vapour-evolution rate of sudden changes in the pressure above liquid nitrogen contained in a 160 litre experimental vessel (9). Similar effects are observed in LNG storage tanks (3). After the initial change the vapour-evolution rate settles to the equilibrium rate exponentially. The surface layer plays an important role in the process, sustaining the difference between the temperature of the bulk liquid which changes only slowly and the temperature of the liquid-vapour interface which responds rapidly to changes in pressure. In the case of a large pressure rise it is possible for the interface temperature to equal or to rise above the bulk temperature in which cause the vapour evolution essentially stops until the heat input has raised the bulk temperature above the surface temperature once more.

In practice, the pressure changes take some considerable time, typically several hours in a commercial LNG tank. Also, a second change may occur before the effects of the first one are complete. However, the equations describing the boil-off rate are simple (9) and can be applied to these practical situations.

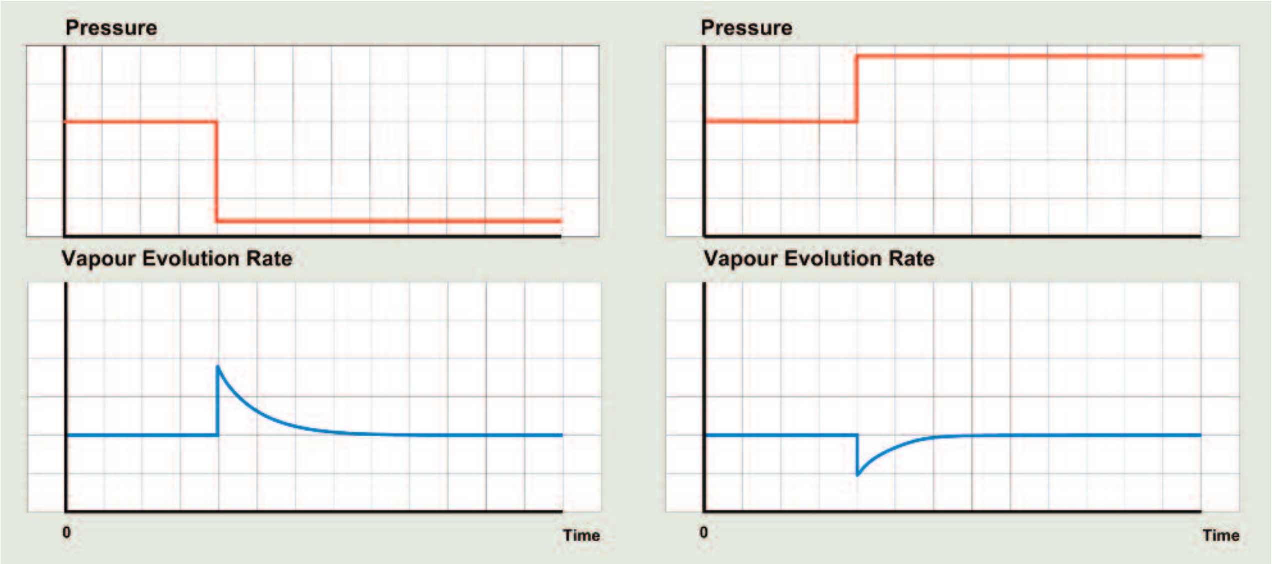


Figure 2.3 (a) Effect of sudden fall in pressure on vapour-evolution rate, (b) effect of sudden rise in pressure on vapour evolution rate.

2.2.2 Physical Disturbances of the Surface

If the liquid surface is agitated, either during top-filling or in some other way, superheated liquid from beneath the surface layer is exposed and the vapour-evolution rate increases. The surface layer is expected to re-establish fairly quickly after the disturbance ceases but there is no known quantitative information on the time taken to reach equilibrium.

2. Rollover Phenomenon

Certain top-filling devices, particularly sprays and splash plates, cause high vapour-evolution rates, because they disturb the surface over an appreciable area. Some experiments in which non-condensable gas was bubbled through LNG (10, 11) resulting in a total vapour evolution to be considerably in excess of the amount calculated from the heat content of the bubbled gas, possibly also because of disturbances of the surface layer. Alternatively or additionally, the gas bubbles may have acted as nucleation centres, causing the superheated bulk liquid to boil and the vapour-evolution rate to increase.

2.3 Fill-induced Stratification

LNG is stored in bulk in large storage tanks with volumes from 40,000 m^3 to ~ 200,000 m^3 with LNG storage tank design advancing and volumes continually increasing. There are four main types of LNG storage tanks:

1. Single containment tanks
2. Double containment tanks
3. Full containment tanks
4. Below ground tanks

The four types are depicted in Figure 2.4. The design of the storage tank used depends upon the age of the process plant, the location for safety and operational consideration, engineering design standards, code requirements and layout constraints.

Single containment tank | Double containment tank | Full containment tank | Below ground tanks

Figure 2.4 Four types of commercial LNG storage tank

The single containment tank design was the common style worldwide pre 1980's and typically had volumes between ~ 40,000 m^3 and 95,000 m^3. Some larger single containment tanks are still being built depending on risk assessment, for example Peru LNG tanks are 130,000 m^3 which were completed in 2010. A single containment tank was selected by Peru LNG due to the site remoteness (hence reduced societal risk) and enough space being available to accommodate different secondary containment features that complied with regulations and represented a safe design installation. Single containment tanks typically feature a primary liquid containment open-top inner tank, a carbon steel primary vapour containing outer tank and an earthen dike for secondary liquid containment.

Double containment tanks are similar to single containment designs except that the outer tank is capable of containing liquid spills in the event of a breach in the inner tank wall. This tank design has a freestanding 9% nickel inner tank and an outer tank made of either prestressed reinforced concrete. However, the roof is still constructed of steel and will not contain vapour produced by failure of the inner tank.

Full containment tanks are the latest design development. National Grid Grain LNG has four 190,000 m^3 tanks which were completed over the period of 2008 to 2010. Full-containment tanks typically feature a primary liquid containment open-top inner tank and a concrete outer tank. The outer tank provides primary vapour containment and secondary liquid containment. In the unlikely event of a leak, the outer tank contains the liquid and provides controlled release of the vapour.

Below ground and underground LNG storage tanks are some of the world largest LNG tanks with capacities over 200,000 m^3. They have advantages in requiring less land area and reduced seismic loading but are expensive and are only common in the Far East Asia.

2. Rollover Phenomenon

As tank design and volumes have advanced, the heel height (an important parameter for consideration in the prevention of rollover) has reduced. This is because increases in storage volume are due to the increased diameter of the tanks, whereas the height has not significantly changed (45,000 m^3 double containment tanks have a height of ~ 50 m and 190,000 m^3 full containment tanks have a height of ~ 55 m). Therefore, for the same volume of heel, the heel height is reduced within the larger capacity tanks.

Due to the advancements in the scale of LNG storage, this has allowed for advancements in LNG trade. The LNG shipping market has witnessed a rapid development in recent years in-line with the rising world LNG trade. LNG buyers started to move upstream and participated in upstream activities such as shipping. Sellers also started to move along the chain, becoming minority owners in shipping and occasionally in regasification plants. The history of LNG vessels shows that since the 1970's the vessels have steadily become larger. From a typical size of 70,000 m^3 in the 1970's, to 125,000 m^3 in the 1980/90's and 145,000 m^3 in early 2000 with some ships over 200,000 m^3. Today, it seems that the ~ 160,000 m^3 has become a popular size, being the "standard" ship size for the large amounts of LNG vessels to be delivered in 2012-2015.

A new trend in the LNG business world is the increasing use of storage and reloading services which are provided by several terminals. This creates new opportunities for short-term trading and developing of geographical arbitrage. The potential risk of rollover when mixing LNG with different densities should always have a high focus.

The composition of these components depends on the source of origin of the LNG. The component characteristics of LNG for global gas fields are detailed in (12) which reports that the methane content of LNG can vary from ~ 89% to 97%. The regasification terminal at National Grid Grain LNG has received LNG from global sources and has contracts for the delivery of cargos from Trinidad (96.8% CH_4 content (12)) and Algerian (88.9% CH_4 content (12)) which are the two ends of the CH_4 component spectrum. Therefore, LNG from a Trinidad source is lighter (less dense) than weathered stock in the LNG tanks, which will have a reduced mixing affinity.

If a storage tank containing LNG is further filled with LNG of different density, then it is possible for the two liquids to remain unmixed, forming independent layers. The stratification is initially stable with the most dense liquid at the bottom.

Fill-induced stratification occurs readily if the added liquid (the cargo) is more dense than the liquid already in the tank (the heel) and filling is at the bottom or if the cargo is less dense than the heel and filling is at the top. Once formed, the layers are stable and can last for long periods of time. Two independent circulation cells are set up in the liquid as shown in Figure 2.4. Both heat and mass are transferred convectively across the interface between cells.

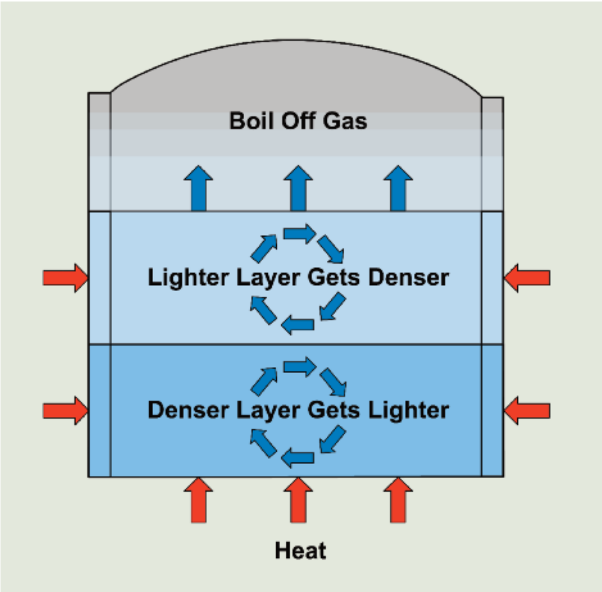


Figure 2.4 Liquid stability stratified in to cells

2. Rollover Phenomenon

Heat entering the top cell is absorbed at its sides and bottom, transported to the surface in the free-convective circulation and lost as latent heat of evaporation at the surface layer. This is similar to the behaviour in the single cell of an unstratified tank. The bottom cell, however, gains heat from the bottom and sides of the tank but can only loose heat at the interface between the two cells by convective mechanisms. Generally, these mechanisms transfer less heat than is lost by evaporation at the surface layer, and so the bottom layer heats up. Sometimes, however, the heat addition to the bottom cell is less than the heat transfer across the interface and the bottom cell cools, tending to increase its density and stabilise stratification.

Figure 2.5 shows the variation of temperature and density of the top liquid with time in the two cells for the bottom cell heating up (case I) and Figure 2.6 shows the variation for the bottom cell cooling (case II). In both cases the liquid in the top cell shows an effect of weathering, heating up and increasing in density with time.

In Figure 2.5 (case I), the temperature of the bottom cell increases rapidly and its density falls. When the densities are equal (or approximately so) the interface disappears and the cells mix. This mixing of cells, which is usually fairly rapid, is called a rollover and is often accompanied by an increase in vapour evolution, see section 2.6.

In Figure 2.6 (case II), the temperature of the bottom cell decreases and the density rises. Rollover is delayed until the top layer weathers sufficiently for the densities of the two cells to equalise.

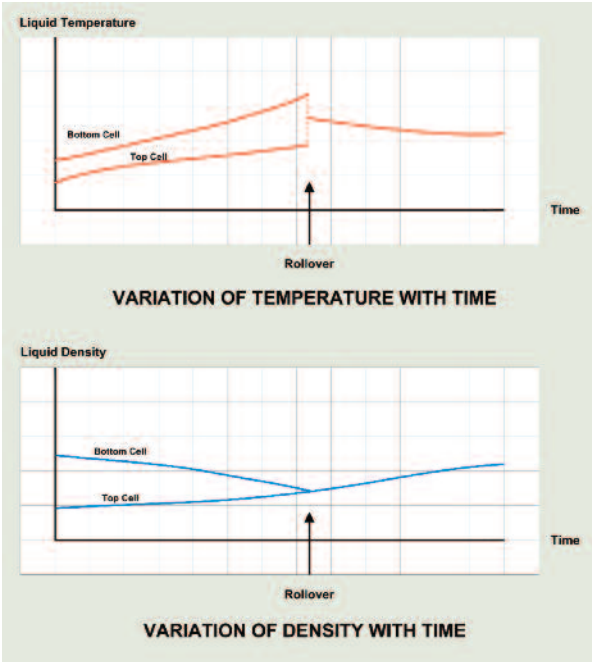


Figure 2.5 (a) Case I, variation of temperature with time
Figure 2.5 (b) Case I, variation of density with time

The likelihood of stratification occurring can be reduced considerably, although not eliminated in every circumstance, by encouraging mixing during filling as follows,

(i) The difference in density of the two liquids can be used to promote their mixing (i.e. by bottom-filling light liquid or top filling heavy liquid),

(ii) Jet nozzles can be used to deliver additional momentum to bottom-filled heavy liquid, increasing entrainment of heel liquid in the flow of cargo liquid and

(iii) Fill tubes pierced holes can be used to distribute cargo liquid within the heel.

2.4 Effects of Nitrogen

Nitrogen, if present in LNG, is the most volatile component, boiling off preferentially and causing the saturation temperature (bubble point) of the remaining liquid to increase. The molecular weight of nitrogen (equal to 28g/mol) is larger than that of methane (equal to 16g/mol) and consequently for most LNG the preferential loss of nitrogen causes the density of the remaining liquid to decrease. By contrast, in a nitrogen-free LNG, preferential loss of the most volatile component (methane) causes increases in both the saturation temperature and the density of the remaining liquid. This characteristic of nitrogen in LNG has two important consequences for rollover, the need for special filling procedures and the possibility of auto stratification.

2.4.1 Filling Procedures

Because weathering increases the density of nitrogen-free LNG, it is usually appropriate to bottom-fill fresh LNG from the same sources as the weathered heel in order to promote mixing. However, if the LNG contains nitrogen, weathering decreases the density initially. In this circumstance it is appropriate to top-fill fresh LNG from the same source as the weathered heel in order to promote mixing, or alternatively to use a mixing nozzle located at the bottom of the tank. Prevention methods are described further in Section 5.1. It is noted that recirculation of LNG from tank to tank within an LNG facility to maintain cryogenic temperatures of pipe work can contribute to the occurrence of stratification. Recirculation flows are of much lower flow rates than the flows associated with ship offloads, this lower flow rate combined with LNG of a high nitrogen content can generate stratification. The nitrogen will flash off when the pressure of the LNG is dropped upon return to the tank, thus generating a thin layer of lighter LNG at the top level of the tank.

2.4.2 Auto Stratification

There is evidence that the presence of nitrogen in LNG can cause a previously homogenous liquid to self stratify. This self stratification is also called auto stratification or nitrogen-induced stratification. Figure 2.1 shows the boundary layer rise associated with auto-stratification when LNG in a storage tank gains heat through the wall. On reaching the surface, the liquid flashes. If there is sufficient nitrogen present*, its preferential loss can cause the flashed liquid to be less dense than the remaining liquid. There is then no driving force for recirculation and the light, flashed liquid would be expected to accumulate near the surface. The accumulation of light liquid would continue until the layer of light liquid reached a height such that the kinetic energy of the liquid in the boundary layer would be insufficient to overcome the potential energy due to density difference and carry liquid to the surface. No further flashing could then occur and the height of the layer of liquid would stabilise.

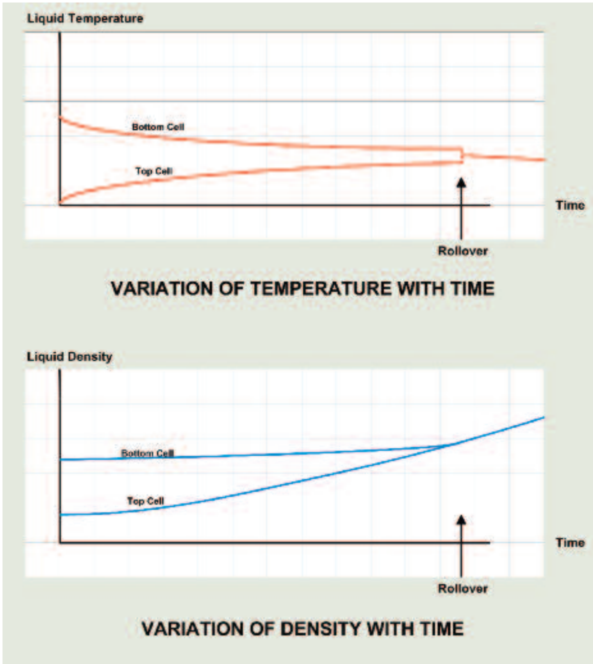


Figure 2.6 (a) Case II, variation of temperature with time
Figure 2.6 (b) Case II, variation of density with time

Chatterjee and Geist (13) give an expression for the stable height (*h*) of the top layer as follows.

$$h = \frac{u^2}{2g}\left(\frac{\rho_1}{\rho_1 - \rho_2}\right) \qquad (2.2)$$

Where *u* is the average velocity of liquid in the boundary layer, ρ_1 is the density of unflashed liquid ρ_2 is the density of flashed (light) liquid and *g* is the acceleration due to gravity.

Once a layer of height given by Equation (2.2) is formed the lower layer can no longer lose heat by flashing and the temperature of the layer (bottom cell) begins to rise. Thereafter, the behaviour is similar to that for fill-induced stratification, rollover occurring when the densities of the two layers equalise, see section 2.3. However, there is one significant difference that after the rollover event the mixed liquid may still contain an appreciable amount of nitrogen, which may continue to drive the process of auto stratification and rollover may be repeated one of more times.

** Chatterjee and Geist (13) do not precisely define critical nitrogen content but state that only mild effects are expected for nitrogen content between 1% and 3%. Even if stratification occurs, which is not certain, the subsequent vapour-evolution rates at rollover are estimated to be only two or three times normal. For 4% nitrogen or higher, auto stratification is an established cause of rollover.*

These findings arose from looking at some incidents at US peak shaving plants where nitrogen content in the LNG was as high as 6% and repeated events occurred which is a characteristic only predicted for auto-stratification. GDF Suez performed, in 1990 and 1991, two experiments on a 120,000 m³ tank at Montoir receiving terminal to study LNG ageing phenomenon. For each test, a homogeneous layer of LNG containing up to 0.8% of nitrogen had been stored inside a tank up to four months. No auto-stratification was reported at the end of these tests. Operational experience has also suggested that LNG is stored in Japanese LNG receiving terminals for long periods of time with no stratification due to convection inside the tanks.

2.5 Other Types of Stratification

Stratification has been observed to develop in cryogenic liquids following pressurisation and in laboratory tests with aqueous solutions in which there was an initial vertical density gradient. Neither type is thought to play an important role in rollover in LNG storage tanks, but they are mentioned here for completeness.

2.5.1 Stratification on Pressurisation

A number of tests (14, 15, 16, 17, 18 and 19) for single-component cryogenic liquids (mainly hydrogen) in tanks up to 170 m³ capacity has shown that raising the gas pressure above the liquid surface can cause stratification to develop within the liquid. Similar effects have been observed in 35,000 m³ LNG tanks (20). This stratification is time-dependent, taking the form shown in Figure 2.7. Initially, the liquid is at uniform temperature roughly equal to the saturation temperature, T_S, at the pressure of the vapour above it. If the pressure is then raised, a region near to the top increases in temperature. This region grows downwards with time. A correlation equation exists (14) that predicts the vertical extent of the region of non-uniform temperature. The Hashemi-Wesson layer at the liquid-vapour interface was not resolved in these tests.

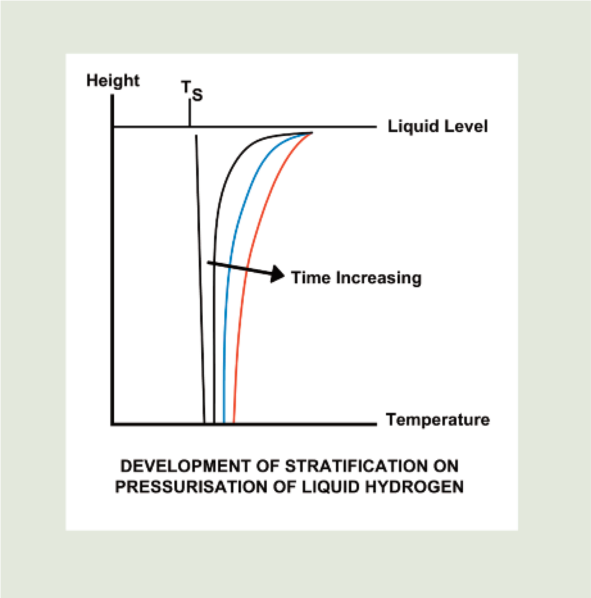


Figure 2.7 Development of stratification on pressurisation of liquid hydrogen

For large pressure rises producing the effects shown in Figure 2.7, the vapour evolution essentially stops, see section 2.2.1, and the heat absorbed through the base and sides of the vessel serves to heat up the liquid and produce stratification. Small pressure rises that reduce the vapour evolution but which are insufficient to stop it would not be expected to produce stratification.

This type of stratification does not produce separate cells and no instances of rollover associated with it are known. However, it does explain the occurrence of pressures in excess of the saturation pressure corresponding to the mixed mean liquid temperatures that have been observed in some closed LNG transports, in particular, a barge and a number of trailers (21).

2.5.2 Double-diffusive Convection

A number of experimental and theoretical studies (22, 23, 24, 25, 26, 27 and 28) have shown that multiple horizontal cells can develop in liquids with an initial density gradient as a result of side heating. The experimental studies are mainly on the laboratory scale and are with aqueous solutions in which the solute increases in concentration in a vertical, downward direction. Cells start to develop close to the side wall and progress towards the centre of the liquid container, ultimately forming complete horizontal cells.

It is possible for a density gradient of the right type to occur in an LNG tank if fresh liquid is poorly mixed with an existing heel and, if certain conditions are satisfied, it is conceivable that horizontal cells could develop also. Rollover might then follow after the cells had agglomerated to such an extent that only two cells remained. According to Griffis & Smith and Narusawa & Suzukawa (25, 26), an important condition for development of the multiple horizontal cells is that the value of the stability parameter, *e*, (which relates buoyancy effects due to concentration gradients to those due to thermal gradients) must lie within certain limits. Unfortunately, the value of *r* for a typical LNG tank is below the range of the experiments and so it is not possible to predict from these studies whether or not multiple horizontal cells can be formed in such a tank.

There are no known instances in which multiple horizontal cells have been detected in LNG storage tanks, whereas fill-induced stratification has been detected by in-tank instruments on a number of occasions. This fact, plus the absence of incidents requiring explanation other than as consequences of fill-induced or nitrogen-induced stratification, suggests that stratification arising from double-diffusive convection is not a problem in operational tanks.

2.6 Characteristics of Rollover

Rollover, the rapid mixing of two stratified cells, occurs when the densities of the cells approximately equalise. Density equalisation is a result of changes in the temperature and composition of the cells brought about by heat absorption from the surroundings and weathering, see Section 2.3. If the mixed liquid has temperature and composition such that it is appreciably superheated with respect to the vapour pressure in the tank, which is frequently the case, there is a sharp increase in the vapour-evolution rate.

2.6.1 Mixing of Stratified Cells

Information on the way mixing occurs is important because the mode and speed of mixing are likely to exert a strong influence on the vapour-evolution rate during an incident. Experiments with Freon (1) and water (2) show that as the densities of the two cells approach one another the boundary layer at the wall tends to penetrate the interface and that away from the wall, waves can develop at the interface. It is therefore probably not necessary for the densities to equalise exactly before mixing begins. The critical density difference for mixing is not known with any certainty but Miyakawa et al. (29) present evidence suggestion that it is small in LNG, about 1 kg/m^3. The Freon experiments (1) also show a dependence of the rate at which mixing occurs on the physical distribution of the heat input to the test tank. Side heating produces "slow mixing", the wall boundary layer penetrating the interface between cells and the interface moving gradually down to the bottom of the tank. Heating from below produces "rapid mixing", the contents of the bottom cell rising bodily upwards on the outside of a downward-moving plug formed by the contents of the upper cell and the interface losing its shape immediately. Combined side and bottom heating can produce either "slow mixing" or "rapid mixing".

A layer of density intermediate between the densities of the two cells has been observed between the cells on several occasions with LNG (29, 30 and 31). Such a layer is likely to affect the mixing process.

It has been suggested (10) that stratification may be terminated by the onset of boiling in the bottom cell rather than by convective mixing of cells. This is conceivable at the tank wall near to the interface between cells if the temperature of the liquid in the bottom cell exceeds the saturation value corresponding to the pressure at the interface (pressure in vapour space plus pressure due to hydrostatic head of liquid in top cell). Boiling at this point would occur first, requiring additional superheat of perhaps 0.5 K to 2 K for bubble nucleation (32). Progressively larger superheat would be required for boiling lower down the wall or at the tank base because of the increasing hydrostatic head of liquid above. Boiling throughout the bulk liquid due to homogenous nucleation is inconceivable, requiring additional superheat of 50 K at least (33). This is how the Partington rollover incident that occurred in 1993 was justified by Baker and Creed (34) who described it. The researchers claimed that around the time of rollover the lower layer had reached its new bubble point under the hydrostatic head of the upper layer.

2.6.2 The Vapour Evolution Rate

Once stratified cells have been created and allowed to evolve over a period of days, the bottom cell cannot cool by evaporation which results in the vapour evolution from the tank being lower than the nominal rate. One of the initial indications that stratification has occurred is a drop off of the BOG evolution rate from the nominal rate and an increase of the temperature of the LNG in the bottom part of the tank, due to heat in leak into the bottom layer which cannot be released at the free surface by evaporation. Uznanski and Versluijs (35) stated that for an experimental trial the presence of stratification reduced the nominal BOG by a factor of five.

When rollover occurs, it is accompanied by a rapid increase in the rate of vapour evolution to a value which can be many times the normal rate. Uznanski and Versluijs (35) stated that the vapour evolution that can be 10 to 30 times greater than the tank's normal boil-off rate, thus giving rise to potential over pressurisation of the tank. Starting from the rollover event the vapour evolution rate declines steadily to the normal operational value.

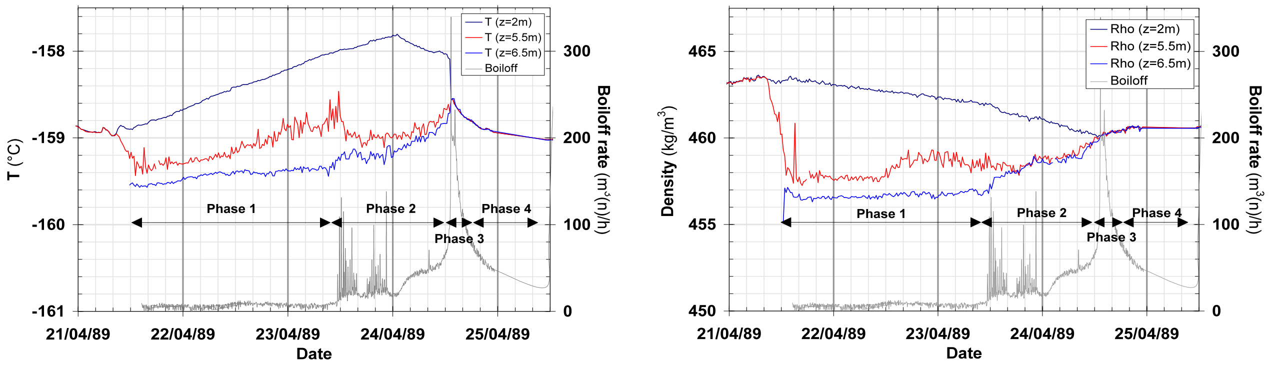


Figure 2.8 Experimental stratification evolution with respect to (a) temperature and BOG rate and (b) Density and BOG rate.

Figure 2.8 (a) and (b) show the evolution of an LNG stratification created in a 500 m^3 LNG tank for experiments conducted by GDF Suez during the late 1980's, (35) and (36). This evolution can be broken down into four distinct phases with regard to BOG rate. During a first phase, the stratified layers can be considered as insulated from one another with respect to both heat and mass and only the lower layer heats up progressively, which decreases the density difference between the layers. During a second phase, interlayer penetration takes place between the two layers, further reducing the layer's density difference. During the third phase, density equalisation occurs, which results in a rapid mixing of the two layers, producing the rollover event. The rollover is characterised by a sudden release of superheat from the lower layer, which is released at the free surface through evaporation. The LNG then progressively loses this overheat and returns to an equilibrium state in a fourth phase.

Bates and Morrison (36) used this research to support their modelling approach for describing the evolution of stratified LNG. The behaviour of moving interfaces has also been reported by Scurlock (37), who arrived at the same conclusion after carrying out over 100 experiments with cryogenic liquids.

3. Incident Data

As part of the research for the revision of this document, the Task Force surveyed GIIGNL members and conducted a literature review for the occurrence of rollover events and additional events post 1983 that build upon the incidents that were reported in the first addition of this study. This study reports 24 incidents of rollover events which are presented in Appendix A.

In summary, the study returned a lesser count of incidents than the study completed as part of the first addition. What may be concluded from this result is that either the first study may have influenced the industry and lessons may have been learnt, thus resulting in fewer incidents recorded as part of the second survey conducted as part of this study; or the second survey had less penetration into the industry. In reality these events are far more common than the documented cases suggest, but LNG operators priorities are in preventing and understanding rollovers, rather than publishing data. The majority of the rollover incidents reported occurred within the 1970 – 1980's. Fewer incidents are reported in the 2000's but rollover events are still occurring with a predictable frequency, implying that the industry still has lessons to be learnt even if the events appear to be of a lesser impact than the events in the 1970's. Out of these 24 incidents, three case studies are provided to demonstrate the different types of rollover events that have occurred.

It is possible to classify incidents as per type of phenomena that occurred. The fill-induced stratification is the most common scenario and the two best documented cases of it occurred in La Spezia, Italy in 1971 (38) and in Partington, UK in 1993 (34). Other fill-induced stratification is more specific to particular sites and local technical limitations, and in recent years a number of rollover incidents were recorded on peak-shaving terminals, where despite the lighter product being fed from the bottom of the tank containing a denser heel, instead of mixing it would float to the surface forming a stratified layer. Investigation performed by Sheats and Tennant (39) attributed this initially unexpected behaviour to two main factors, firstly being the lack of an efficient mixing nozzle, and secondly a very low filling rate.

It may be possible to classify incidents as per situational root cause:

- Peak shave – Less flexible operationally and of a generally older design with less instrumentation
- Import Terminals – More flexible operationally and of a generally newer with instrumentation
- LNG carriers – Incidents are more hidden from the public domain and therefore less reported

The results from the study show that rollover incidents continue occurring over the LNG industry, implying that lessons still need to be learnt. The study reported incidents associated with new commercial shipping arrangements such as partial offload and reload, signifying that the industry should consider more attention within this area, particularly considering rollover in the design of ships tanks. The rate of rollover incidents might be an emerging theme with an increasing diversification of LNG supply sources caused by a growing number of liquefaction plants around the world along with an increase in short-term trade. This combined with the industries transition into a new growth phase with new technology, such as FPSO (Floating LNG Production, Storage and Off-loading), bulk breaking and small scale LNG, ship to ship reloading, LNG as a fuel and growth of road tanker sector may see rollover incidents continue in the future.

3. Incident Data

3.1 Case Studies

3.1.1 Case Study 1: LNG Rollover at La Spezia, Italy, 1971

The terminal had two vertical cylindrical single containment 9% Ni storage tanks each with a capacity of 50,000 m^3 and a maximum design pressure of 50 mbarg. Bottom filling was achieved by a side entry point and recirculation was achieved via a top connection. The tank that was filled had a heel of 5,170 tonnes with a density 541.7 kg/m^3 (40) to which a cargo of 18,200 tonnes of a density of 545.6 kg/m^3 was added. Prior to discharging its cargo, the “Esso Brega” LNG carrier had been berthed in La Spezia for more than one month, during which time the cargo had weathered and warmed. When this heavier warmer LNG was loaded through the bottom fill of the LNG storage tank it stayed on the bottom forming a layer, with the lighter cooler tank heel being displaced upwards with only minimal mixing.

About 30 hours after the loading had commenced rollover occurred. The tank relief valves lifted for approximately 1 hour and the process vent discharged at high rates for a further 2 hours after the tank relief valves were closed. The vapour release peak was estimated at 10 tonnes/hour. It is calculated that 185 tonnes of LNG vapour was released in total, 89 tonnes from the tank’s roof vents and the remainder from the process vent on site (41). Some vapour drifted offsite to a public road and as a precaution the public road was closed and the LNG carrier was moved off the berth. No ignition took place and no injuries were sustained but some minor damage to the roof of the tank occurred. Sarsten (38) studied this incident in further detail.

The incident at La Spezia was the first significant rollover event that occurred on an LNG storage tank to be reported. The incident led to important changes in storage tank design, instrumentation and operations across the LNG industry.

3.1.2 Case Study 2: LNG Rollover at Partington, UK, 1993

Tank No. 2 at the Partington site had a heel of 17,266 tonnes of LNG and a total of 3,433 tonnes of liquefaction product was added over a period of 24 days (40). During the final 13 days of liquefaction production, two significant events occurred. Firstly a cryogenic distillation plant was commissioned that reduced the heavy hydrocarbon and carbon dioxide content of the feed gas to the liquefaction plant, and secondly the nitrogen content of the feed gas to the plant reduced due to the shutdown of a specific gas field that supplied the UK gas transmission system.

After 68 days following the end of liquefaction production, the tank pressure started to rise rapidly and both the process relief valves and the emergency relief valves lifted resulting in approximately 150 tonnes of vapour being vented to atmosphere from the tank over a 2 hour period. The pressure in the tank did not exceed the design pressure and the tank was not damaged.

Calculations undertaken as part of the investigation into the incident indicated that the tank heel prior to filling was approximately 446 kg/m^3, to which 1,533 tonnes of LNG at 449 kg/m^3 was initially added to the tank followed by 1,900 tonnes of the lighter LNG, resulting in a product density of 433 kg/m^3. The first phase of the run would have been expected to mix with the heel, but the lighter second phase would have stratified. In the first 58 days after filling approximately 160 tonnes of LNG had boiled off whereas calculations showed that 350 tonnes would have been expected to boil-off if no stratification was present.

3. Incident Data

As a result of the incident, the operator amended their operating procedure at the Partington plant and other peak shaving sites across the UK for filling tanks and identifying stratification. These included determination of heel density by analysing export gas, controlling LNG density from the liquefaction plant to ensure it does not differ from the heel by more than 5 kg/m^3, limiting nitrogen concentrations in the tank to less than 0.8% after filling and regular analysis of boil-off composition and rates. If stratification was detected then the contents of the tank were circulated from bottom to top of the tank to promote mixing and release superheat from the LNG. Baker and Creed (34) studied this incident in further detail.

3.1.3 Case Study 3: LNG Rollover on a Moss Rosenberg Type LNG Carrier

It was believed that rollover on a Moss Type LNG carrier was unlikely to occur because the spherical shape of the tank would enhanced the convection current and ensure thorough mixing of the tank inventory which would be further aided by the vessel's motion during transportation (40).

The first publication of this rollover Task Force (1983) stated that there had been a rollover aboard an LNG ship that occurred shortly after completion of loading operations, but there were no details available to publish as part of the study. The original rollover Task Force also noted that stratification had occurred onboard an LNG carrier on another occasion. This second event was confirmed by the recording of LNG densities during unloading and by an unusually high vapour-evolution rate, more than three times the normal value. The current Task Force have reported the occurrence of a rollover event on a Moss Rosenberg type LNG carrier, the events are summarised below.

In 2008, a Moss Rosenberg type 125,000 m^3 LNG carrier discharged a cargo in the Far East that had been loaded in the Atlantic Basin keeping over 8,500 m^3 of LNG as heel in two cargo tanks (No. 3 and No.4) for the return voyage to the Mediterranean to load (40). After 8 days at sea the vessel received orders to change course and load in a port in the Far East where it arrived 17 days after leaving the discharge port, arriving with a heel of over 5,000 m^3 of LNG. The port where the vessel loaded was a receiving terminal and the loading rate was less than half of what would normally be expected; also the vessel had to interrupt loading for several hours to ensure that the cargo tanks were cooled to acceptable limits and both of these factors may have contributed to the stratification of the tanks contents. The density of the cargo loaded in the Atlantic Basin was 427 kg/m^3, that of the 8,500 m^3 heel 434 kg/m^3 and that loaded in the Far East 454 kg/m^3, nitrogen content was negligible.

After 24 hours from leaving port the levels were seen to increase in tanks No. 3 and No. 4. After 5 days, whilst the vessel was waiting to berth at the discharge port, the tank pressures were seen to rise, accompanied by a drop in the tank levels in 3 and 4 tanks as rollover occurred. The crew closed the vapour valves from tanks 1, 2 and 5 to send as much vapour as possible to the boilers from No. 3 and No. 4 tanks, which peaked at 200 mbarg. Shortly after this event occurred, the vessel berthed at an importation terminal and was able to send vapour to the shore flare to manage boil-off and commence custody transfer.

This was not considered to be a serious rollover event when compared with the La Spezia incident, but demonstrated that LNG carriers can experience stratification and rollover if heavy LNG is loaded under a heel of lighter density. The changes in tank level were more apparent because a spherical tank will have a greater change for a given volume than a prismatic tank when the tank is fully loaded. At no time did the tank pressures exceed the design pressure nor did the cargo tanks pressure relief valves lift (40). Knowledge of how to manage different density cargos by the ship operations team could have attributed to the occurrence of the incident. The changing shipping pattern of the vessel was also an attributing factor. These factors are a concern as this result may highlight a future trend in the industry as LNG as a commodity is utilised in an ever increasing manner with different ways of operating, new technologies and new operators / users.

4. Measurement of Stratification

The first signal of the presence of stratification in a tank is a decrease of the boil-off rate of the tank and an increase of the temperature of the LNG in the bottom part of the tank. This temperature increase is due to the fact that the heat leaks in the bottom layer are not evacuated at the free surface by evaporation but contribute to that layer's temperature increase. Another sign that conditions exist for a rollover event is the stratification of the stored LNG. This results in the development of two distinct layers of liquid densities within the product in the tank. All of these effects are measurable and tank instrumentation can be included to detect these stratifications by measuring temperature and/or density at various levels within the stored LNG. Software is also available that uses data from instrumentation on the storage tank to predict when a rollover incident may occur which may be many days after a filling operation has been completed.

Since the publication of the first rollover study in 1983, the instrumentation available to the industry has advanced. In those days a technician would take a sample of the stored LNG from one of the LNG pumps while it was operating. The sample would be run through a chromatograph in a laboratory. The results would be returned to the plant via interoffice mail. These sampling routines would take place prior to the start of any operations to refill the LNG storage tank. It is obvious to foresee that this procedure could lead to errors where the analysis results were either delayed returning to the plant or lost resulting in incorrect filling, i.e. top fill when it should have been bottom fill or vice versa. Today LNG plants are equipped with sophisticated and unmanned systems to analyse the properties of the LNG in situ with real time results available to operators. Gas chromatograph-based techniques analyse vaporised LNG samples, which provide a routine means of providing LNG composition and other properties. This data is then sent to the SCADA system which informs the operators in the control room as to the quality and density of the LNG both incoming and existing. This information combined with a LTD travelling gauge provides a useful setup for the prevention and control of the stratification phenomenon. Moreover, the present requirements for the design and operation of LNG plants are governed by internationals codes, such as:

- "Tank Systems for Refrigerated Liquefied Gas Storage" (API 625),
- "Installation and Equipment for Liquefied Natural Gas – Design of Onshore Installations" (BS EN 1473), and
- "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 (BS EN 14620),

These codes require that LNG storage tanks be equipped with a density measurement system to monitor the density of the LNG over the full liquid height. The following is a summary of the different types of instrumentation used on LNG storage tanks.

4.1 Useful Measurements

LNG tanks are equipped with intelligent tank gauges with high accuracy liquid level, interface level, density and density profile measurements with the following three main purposes:

- Detection of stratification,
- Monitoring the effectiveness of methods of preventing or eliminating stratification and
- Obtaining data for investigation of any incidents that occur.

A list of useful measurements for these purposes is as follows:

- Vertical temperature profile in LNG
- Vertical density profile in LNG
- Vapour withdrawal rate
- LNG level
- LNG filling and withdrawal rate
- LNG recirculation rate
- Composition
- Tank pressure

It is generally not necessary to make all these measurements: for example, stratification can be detected from the temperature profile, from the density profile, from analysis of composition or from the vapour evolution. Also, not all parameters need to be monitored continually. The choice of which measurements are made and when they are made ultimately depends on individual site conditions and requirements.

4. Measurement of Stratification

4.1.1 Instruments in Use

The instrumentation on new LNG storage tanks has developed into a standard configuration. The setup normally includes two level gauges (either servo or radar) with associated temperature arrays for average LNG temperature, a dedicated high level gauge, a level temperature density (LTD) gauge for profiling, and some combination of skin temperature measurement for cool-down monitoring and leak detection (Figure 4.1). The LTD travelling gauge is an instrument that has been designed to collect the temperature and density over the entire depth of the liquid. This is accomplished by traversing a single, multifunctional probe through the height of the liquid and recording the temperature and density at present intervals. This operation requires less than an hour depending on the height of the liquid in the tank and can be done as often as desired. It is normally done after a significant change in tank conditions and once a day under static conditions (39). The association of a travelling liquid temperature density (LTD) gauge with rollover prediction software gives the operator an integrated predictive tool with real time validation, in order to optimise the management of LNG storage.

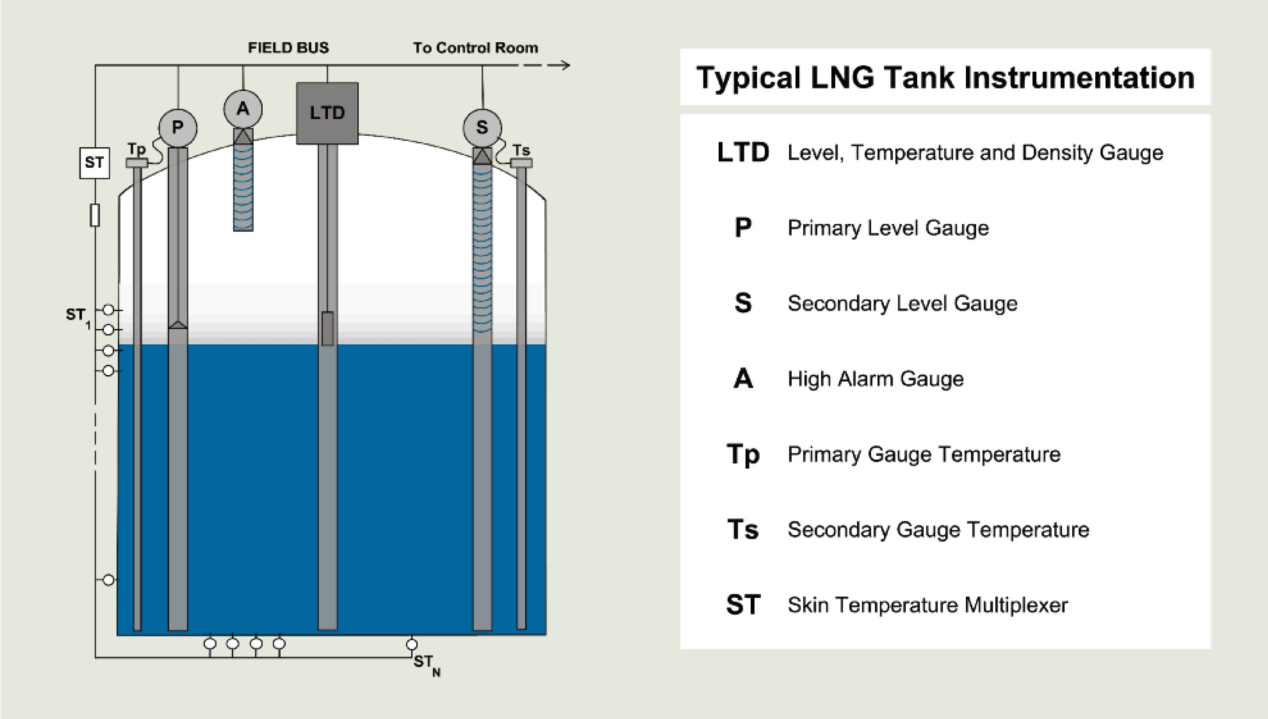


Figure 4.1 Typical LNG Tank Instrumentation

4.1.2 Vertical Temperature Profile in LNG

One of the features of the LTD device is to measure the temperature profile across the height of the LNG storage tank. Figure 4.2 shows real operational data for temperature variation across the height of a tank that contains stratified LNG. There is a clear transitional region for of both temperature and density around a level of 1500 mm as measured by a travelling gauge. The graph also depicts how both the measured parameters of temperature and density evolve with respect to time. Calibrated platinum RTD's are typically used for temperature measurement which have an accuracy of ± 0.1°C and a high level of resolution (typically 0.01°C) to be able to detect changes in the temperature of stratified layers. LNG storage tanks are also normally installed with temperature sensors on the tank walls for cool down monitoring purposes. These temperature probes are not suitable for detection of LNG stratification as they are not very accurate.

4.1.3 Vertical Density Profile in LNG

A key measurement for determining the presence of stratification is a vertical density profile across the height of the LNG storage tank. This measurement is typically performed by use of a LTD device. The accuracy range for this type of instrument for density measurement is typically 0.1% of range, 0.5 kg/m^3, however, the accuracy of the measurements is not as important as the resolution and repeatability. What is important of this type of device is that the resolution is high enough to detect changes in the density of potential layers within the storage tank. Figure 4.2 is an example to show a typical result for density measurement across a storage tank height for stratified LNG.

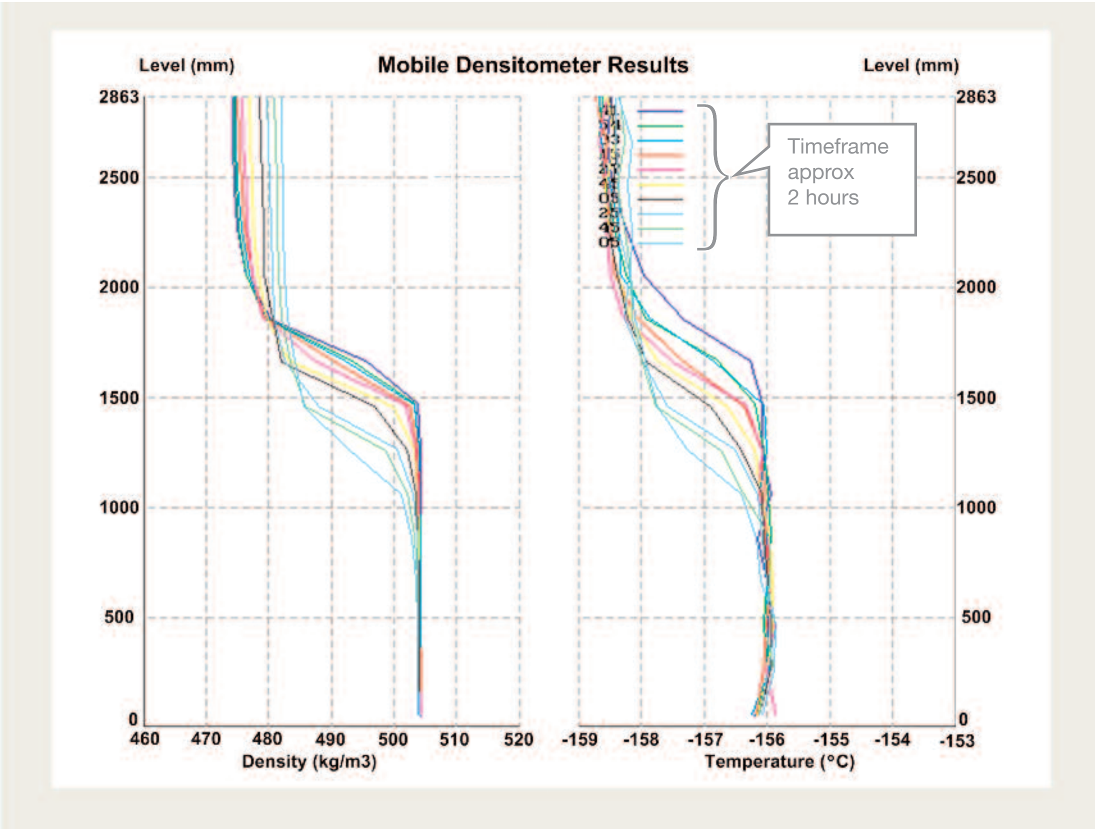


Figure 4.2 Temperature and density profiling across an LNG tank height for stratified stock

Capacitance gauges instruments were historically used for the purpose of measuring vertical density profiles. However, capacitance gauges are seldom installed in newly constructed LNG storage tanks as other types of instrumentation have been developed that are more accurate.

4.1.4 Vapour Withdrawal Rate

Turbine meters and orifice plates predominate as gas flow meter used for BOG flow measurement. Instruments need to be able to withstand and measure high vapour-evolution rates during an incident. The vapour withdrawal rate can also be deduced from the BOG compressor capacity and experienced operators will detect a deviation from the normal compressor demand, signifying that stratification may exist.

4.1.5 LNG Level

Float gauges, displacement gauges and radar gauges predominate. Recording systems are available these can be useful for monitoring liquid loss before and during an incident.

4.1.6 Other Measurements

LNG filling, withdrawal and recirculation rates are known from the pump characteristics.

Composition is universally determined by gas chromatography, accurate techniques for which have been extensively developed for custody transfer purposes.

Tank pressure is monitored during normal operation. During rollover the data are useful for three purposes;

- to ensure that operating limits are not exceeded,
- for estimating the vapour evolution if direct measurements are not made
- for correcting any measurements of vapour withdrawal that are made (the ullage space may retain a significant quantity of vapour if the pressure rises appreciably).

4.2 Peak Shave Plants

Peak shave plants are typically older facilities that have issues with rollover occurrences primarily due to the fact that their design and build predates significant advances in rollover identification and prediction techniques. Therefore, they typically only have top fill capabilities during liquefaction and limited instrumentation installed. The Chattanooga Gas Peak Shave Facility, USA operated safely for many years without any specialised instrumentation to detect and minimise the consequences of rollover (39). The main indication of an impending rollover was a decrease of the BOG rate and an increase in temperature the bottom of the tank. The LNG storage tank was retrofitted with LTD system together with an LNG management data acquisition software system. The combination of this equipment provided the ability to collect temperature and density profile information over the entire height if the LNG stored in the tank and analyse the data to assist the operator in making the correct decision for stock management. Of particular importance in this application is the fact the system may be installed in a tank in service and does not require a stilling well to protect the probe. Whilst the plant had operated safely for many years without this instrumentation, increased requirements from regulatory agencies were one of the primary drivers for the installation of this equipment to demonstrate that the plant was being operated safely at all times (39).

5. Prevention of Stratification Leading to Rollover

The incident at La Spezia is the first known rollover event that occurred on an LNG storage tank. This incident led to important changes in storage tank design, instrumentation and operations. Also, the Partington incident led to further changes in the LNG industry and in the UK this led to all LNG tanks being fitted with densitometers. The learnings from these incidents fed into international codes such as API 625, EN 1473 "The design of onshore LNG terminals", and NFPA 59A "Standard for the Production, Storage and Handling of LNG" now require that LNG tanks be equipped with the necessary systems to mitigate potential rollover conditions. Additionally, they require that a top and bottom fill be provided to allow the mixing of tank contents.

The possibility of a sudden release of large amounts of vapour and the potential over-pressurisation of the tank resulting in possible damage or failure is recognised by the major design codes. EN 1473 and NFPA 59A, both require this phenomenon to be taken into consideration when sizing relief devices. Whilst the relief valves may prevent damage to the tank, LNG vapour is not only flammable and heavier than air on release, but a valuable commodity and a potent greenhouse gas and therefore venting should be avoided whenever possible.

Potential stratification may be prevented during filling operations by loading the denser liquid above the heel of a lighter stored LNG or loading a lighter LNG into the bottom of the tank combined with proper filling rate and/or mixing nozzle so that the light grade does not float to the surface. This creates mixing of the unloaded product with the stored contents. If stratification is detected, product can be moved to prevent rollover from occurring. Product can be recirculated by moving it from the bottom of a particular tank to the top of that same tank. Alternatively, the product can be transferred from the bottom of one tank to the top or bottom of an adjacent tank. Top and bottom fill nozzles designed to promote mixing (in conjunction with the in-tank pumps) are used to move the product for loading, recirculation, and transfer operations. Not only does this move the product to areas with similar compositions, but it also serves to mix the product and release any trapped heat or vapour within the product being moved. Mixing may also be promoted with mechanical agitators such as jet mixing nozzles on the top-filling and mixing slots on the bottom-filling.

Informed LNG storage tank design combined with appropriate plant operational procedures can mitigate the risk of rollover. Mitigation measures that are used are:

- Stratification inside storage tanks is avoided by top or bottom filling according to heel and fill LNG densities, bottom/top recirculation, mixing the liquids by filling using jet nozzles and distributed fill systems
- Different compositions of LNG are stored in separate tanks
- Specify LNG with nitrogen content less than 1%
- Monitoring of LNG density and temperature over height of tank
- Monitoring of total boil-off and heat balance to detect superheating
- Use of software based on LNG tank thermodynamic modelling to predict potential for roll-over
- Ensure LNG residence period in tank is not too long
- Process relief systems and safety valves are designed to handle rollover effects

Out of all of these mitigation approaches, the direct measurement of density across the tanks' height is the primary means of detecting stratification. During stratified conditions the bottom layer often becomes superheated, but monitoring BOG rate is a better indication of potential stratification, rather than direct measurement of the temperature of superheated LNG.

5. Prevention of Stratification Leading to Rollover

5.1 Prevention Methods

5.1.1 Bottom Filling

If the incoming LNG is lighter than the heel in the tank, a bottom filling operation will generally ensure a complete mixing of the two LNG grades, with little or no chance of stratification. The boil-off gas production, generated due to the temperature rise of the LNG during transfer from the LNG carrier to the filled tank, is limited by the hydrostatic pressure at the bottom of the tank. The bottom filling device (Figure 5.1) consists of a tube attached to the support of the tanks and goes down vertically from the top to the bottom of the tank. At the bottom of the tube, there are some slots that direct the incoming LNG into several directions to promote mixing with the LNG in the heel. The bottom filling device is positioned at the edge of the tank near the tank wall. The location, diameter, number and width of slots and other characteristics depend on the specific design.

5.1.2 Top Filling

If the incoming LNG is heavier than the stored LNG a tank top filling operation will avoid stratification and the risk of subsequent rollover, but this usually results in excessive vapour generation due to the flashing of the injected LNG into the tank's vapour space and subsequent increase in tank pressure which must be managed. A simple solution to this is to reduce the loading rate, but this may not always be commercially acceptable and other means may need to be adopted. Furthermore, top

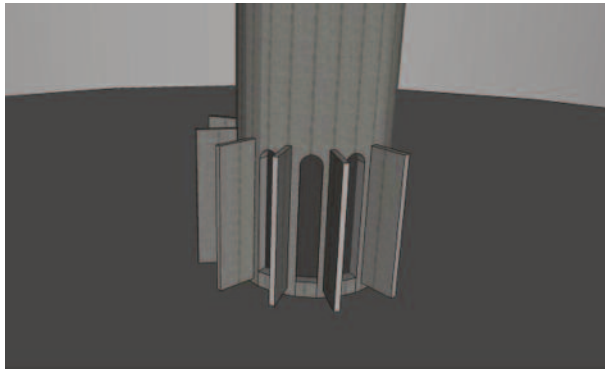


Figure 5.1 Model drawing of a typical bottom filling device

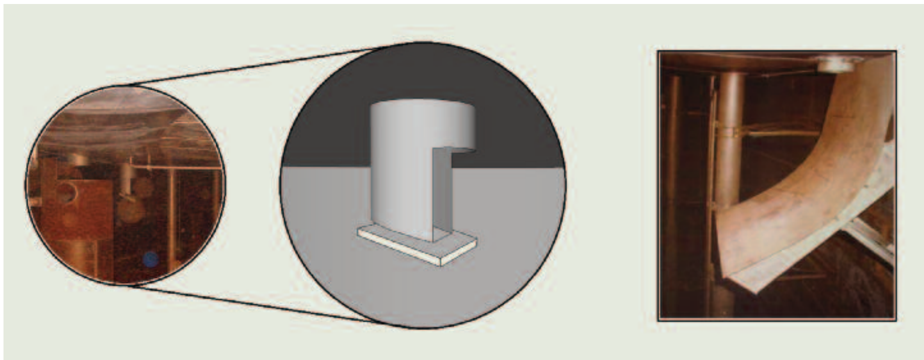
filling is not generally provided on LNG carriers, unless they have been modified for use as a floating storage regasification unit (FSRU) when they are often provided with top fill connections.

Top-filling devices such as sprays or splash plates are common and appear to be fairly effective insofar as they cause large vapour evolution rates. However, it is thought that this type of device creates droplets that can be carried over into the vapour line, masking the effectiveness of the device and sometimes making the vapour evolution rate excessive.

One method of reducing overall vapour generation when top filling is to lower the tank pressure prior to filling the tank; this will create more boil-off and drop the temperature of the heel. Immediately before filling commences the tank pressure is raised to above normal operating pressure to limit the amount of LNG that flashes off when discharging into the tanks vapour space. This raised pressure is maintained throughout the loading process and when filling is complete the tank pressure is slowly returned to its normal level.

A top filling device is a pipe that enters into the top of the tank though the dome chamber (Figure 5.2). Normally the device consists of a plate at 45° to the direction of flow. When incoming LNG comes into contact with the plate it produces droplets of LNG that fall down the tank into the heel.

Figure 5.2 Example of two types of top filling devices



5.1.3 Filling using Multi-orifice Tube

A mixing device that comprises of a vertical tube drilled with numerous holes over part of its height. The device has the advantage that the discharge rate for a given pump head is higher than for a single nozzle. It is necessary for the holes to be located so that they are submerged for most of the time to avoid excessive vapour evolution. Additionally, the holes are arranged so that the jets miss internal tank fitting, instruments etc.

5.1.4 Jet Nozzles and Other Mixing Devices

A jet nozzle fitted to a fill line located at the bottom of the tank can be very effective in preventing stratification, but there must be sufficient head in the filling line to ensure the jet can reach the surface of the liquid and sufficient time must be allowed to ensure the mixing process takes place in all of the tank contents. Diffusers at the bottom of the fill line can also aid mixing.

5.2 Filling Logistics

In order to prevent stratification, it is advised to adjust the mode of filling the tank (top or bottom) to the relation between density of the existent heel and cargo. If density of the heel is lower, filling heavier liquid from the top will promote natural mixing. Provided a proper mixing nozzle and a suitable filling rate are possible (in order to avoid the fill-induced stratification described earlier) filling lighter liquid from the bottom will also promote mixing. It is quite common to top or bottom fill liquid according to whether it is more or less dense than the heel in order to avoid stratification, but it needs to be used with caution: cases of stratification or rollover in operational tanks following the correct choice of filling point are known.

A common problem with top filling is that this mode of operation causes a large vapour evolution rate. Older sites tend to only have top filling to tank fill. A way of avoiding stratification is to put liquids of different density into separate tanks. This may reduce operational flexibility, and difficulties can arise matching storage tank and ship capacities and scheduling deliveries. It may also be necessary to send out liquid from more than one tank at once to produce a composite mixture for control of the heating value.

Tank stock management for optimisation of use of gas quality blending utilities often sees tanks filled with LNG of different ‘quality’. A ship acceptance model is typically used to carry out calculations and support the strategy for stock management during unloading. For LNG receiving terminals there is a need for a continuous flow of LNG from the in-tank pump discharge to keep the unloading lines cold. Due to continuous recirculation, stock transfer will take place from the tanks with in-tank pumps running to all other tanks. Thus consideration for generation of stratification should be taken for stock management due to LNG transfer during reduced export or holding conditions.

5.3 Management of Stratification and Rollover

Stratification can be destroyed by recirculation, by rotating stock between storage tanks and by sending out liquid before rollover can occur (this may require stock to be exported during less commercially viable periods). To use these methods with confidence, the time to rollover needs to be known, information that can be obtained by modelling, this covered further in Section 6.

Breaking up stratified cells can be achieved by external recirculation of LNG by running the in tank pumps and drawing in the bottom layer, circulating this LNG around the plant (i.e. to the jetty) and feeding it to the top of the tank. However, this process has a cost associated through increased power consumption from running additional pumps and compressors and depletion of stock by production of BOG which will need to be exported. This process may also cause rollover to occur sooner, but with less severity. The reason is that by recirculating the liquid we effectively speed up the process of densities equalisation, which is the criterion for rollover occurrence. If a sophisticated tank management system is provided, the operator will have real time information on how long he has to break up the stratification.

In recent years, following work pioneered by GDF Suez, there has been a growing trend to intentionally induce density stratification. This approach is used to reduce high LNG boil-off gas rates, particularly when top filling is required for heavier cargo. Thus BOG compression costs can be reduced both during and after unloading LNG carriers. These procedures require the sophisticated tank management systems and a means to break up the stratification as referred to earlier.

5.3.1 Detection of Stratification and Prevention of Rollover for LNG Carriers

Rollover risks for shore LNG plants are well documented and understood and the risk of a rollover occurring on an LNG ship has always been considered low (40). This is because LNG ships often maintain a dominant trading pattern for specific vessels, therefore the opportunity for rich cargo to be loaded beneath a lean heel is reduced. Also, due to the process of weathering the remaining heel in the ship is expected to be richer than the cargo that is being loaded.

However, as reported in Section 3.1.3, at least one rollover has occurred within a ship. The incident arose because there was an unusually large heel aboard and the heel was lighter then the incoming cargo. It is also possible to foresee a set of circumstances that could lead to rollover where a ship is being used as floating storage for an extended period of time, which is then topped up with LNG from a richer source (40). Because ships do not normally have either the instrumentation to detect stratification, or the means of mixing the tanks, the best way to manage stratification is to avoid the conditions required to instigate it. Steps such as keeping ships on dedicated trading routes (i.e. within a rich or lean region), reducing the heel for ships arriving at load ports and floating storage being replenished with LNG from the same source, these steps are all deemed as good practice to reduce the risk of stratification. However, if the circumstances for stratification present themselves, then (40) suggests the following actions to mitigate the potential risk. The advice given in (40) is to:

1. Consolidate the heel into one tank.
2. Partially load a second tank to a level such that there is room to transfer into the tank the entire heel.
3. Close the manifold liquid valves - leaving the vapour manifold open.
4. Transfer the heel into the partially filled tank. This should be done using the ship's cargo pumps as fast as safely possible, prudence and vapour generation permitting. The reason for speed is to promote as much turbulence as possible in the bottom of the receiving tank to aid mixing.
5. Do not load any further LNG into the tank containing the mixture.
6. Complete loading the other tanks as per normal procedures.

The procedure above is to be carefully discussed between ship and shore before commencement of loading. It should be noted that the transfer and mixing process may generate significant amounts of vapour.

5.4 Operating Methods

This section summarises how operators for different types of LNG sites put the above recommendations into practice.

5.4.1 Statoil Hammerfest LNG Export Terminal Method

The LNG storage and loading facility is controlled by a central control system which is operated from the Central Control Room. In order to prevent LNG tank roll over phenomenon, each tank is equipped with a level-density-temperature device, which measures and indicates liquid density and temperature at various levels through the LNG tank inventory. Whenever a density difference of more than 1.0 kg/m^3 or if the difference of product temperature between any two layers is more than 0.5°C, or a change in level of ~ 2 m is observed, it is considered that stratification of the LNG inventory into distinct layers may be about to occur. The density measurement system will raise an alarm if the density difference is more than 1.0 kg/m^3. If this happens the operator takes immediate action to eliminate the stratified layers to prevent a potential rollover condition. Generally the stratification will be eliminated by mixing of the tank's inventory or through inter-tank transfer. Tank recirculation will be undertaken by operating one of in-tank pumps on spillback to the tank. LNG is taken from the bottom of the tank and is filled into the top of the tank via the top filling device and the layer is gradually reduced.

5.4.2 National Grid Grain LNG Import Terminal Method

The LNG storage tanks are routinely monitored using densitometers to look for stratification within the stored liquid. This is conducted at least once per week and after ship unloading.

If the densitometer indicates that stratification exists, the tank is mixed by running the in-tank pumps on spill back. LNG is circulated until the density measurement indicates a top to bottom variation less than 2 kg/m^3 and the temperature measurement indicates a top to bottom variation less than 2°C. Additional boil-off compression capacity is required during the circulation process.

If a rollover condition would occur then the increased BOG would trigger high pressure alarms, release gas to the vent and lift tank relief valves. High pressure would also stop the unloading of cargo if it is in progress and would trip the recirculation of LNG through transfer pipelines from the jetty.

A typical emergency response would include the following steps:

- Maximise BOG disposal via site compressors and relief system.
- Identification of the likely direction of release based on wind data.
- Determination of a safe evacuation route for staff.
- Remote shutdown of sources of ignition potentially in the path of the dispersing gas cloud.

5.4.3 National Grid LNG Tewksbury, MA

The Tewksbury facility is a storage site that is filled by road tankers. The site deploys a strict policy when receiving liquid via road transport; lighter-colder liquid is bottom filled; heavier, warmer liquid is top filled. This method maintains a stable well blended liquid in the tanks. Storage sites of this nature may only empty half the contents of a tank during the vaporisation season. An average operating condition for a winter is to empty the tanks by 50% to create ullage for the summer refilling period. Also, the density of the LNG is monitored and if it corresponds to a Gross Heating Value approaching 41 MJ/m^3 then an export is run to vaporise to lower the tank level and create space for lighter LNG refill. Export also decreases the depth of the lower layer if the tank becomes stratified.

5.5 Safeguards against Rollover

In the event of a rollover, there may be a sudden release of vapour that results in an increase in the tank's internal pressure. This increase in pressure must be accommodated to avoid damaging the tank. The most common way to manage this increase is by providing pressure relief valves that vent the over pressure to a flare or to atmosphere. Other methods for lesser occurrences create the need to run boil-off compressors to recover the gas and send it to lower pressure distribution networks and minimise loss of product and environmental impacts. As previously stated in Section 4, Sheats and Tennant (39) reported that for the Chattanooga Gas peak shave plant, the normal BOG rate would be approximately between 14,158 and 19,822 m^3/day. Prior to rollover, the rollover rate would drop considerably (8,495 m^3/day). During the actual rollover event at the facility, the rate would rise to a range of 67,960 to 76,455 m^3/day. There are two BOG compressors at this site. During normal operations one compressor is required. During a rollover event, two compressors would be required to handle the load. Anything that would make one of the compressors unavailable (such as planned maintenance or a breakdown) would increase the likelihood of venting gas to the atmosphere to protect against tank over pressure.

5. Prevention of Stratification Leading to Rollover

International codes such as EN 1473 and NFPA 59A require that pressure relief be provided to each tank as a last layer of defence to protect against tank over pressurisation during a rollover event. These codes also establish relief sizing criteria that are expected to handle a "typical" rollover scenario. EN 1473 requires that the venting requirements for a rollover scenario be determined by a validated model. If a validated model does not exist, the venting requirement may be conservatively taken as 100 times the calculated boil-off. Alternatively, NFPA 59A requires that the relief system be capable of venting 3% of the full tank contents in a 24 hour period.

For information the design for relief valve sizing for an LNG tank used the guidance in appendix B of EN 1473. Extract given below;

The boil-off due to a roll-over (V_B) shall be calculated using appropriate validated models. In case where no model is used, the flow rate during rollover shall be conservatively taken equal to:

$V_B = 100 \times V_T$

This flow rate corresponds approximately to the maximum flow rate observed in the past during a real roll-over. Where V_T is the maximum flow rate of a tank boil-off due to heat input in normal operation is to be determined by assuming ambient air at the maximum temperature observed in the course of a hot summer day.

The approach NFPA 59A takes is to consider the minimum reliving capacity and states:

The required relieving rate is dependent on a number of factors, but sizing will be based on the NFPA 59A Section 7.8.5.3 (2006 edition) requirement that: "The minimum pressure relieving capacity in pounds per hour (kilograms per hour) shall not be less than 3% of full tank contents in 24 hours."

In Asia, the Japan Gas Association (JGA) is an association consisting of city gas utilities that develops technical standards and recommended practices that are used in Asian countries. Their suite of Recommended Practices include:

- Recommended Practice for In-ground type LNG Storage tanks (RPIS),
- Recommended Practice for Above ground type LNG Storage tanks (RPAS),
- Recommended Practice for LNG terminals facilities.

Rollover features within the Japanese design codes but a detailed procedure is not described within the code. Therefore, Japanese utility companies allow for rollover within the design by considering the specific features of the LNG terminal. As the result, API codes may also be used in addition to these standards depending on judgment of each company. For Japanese design codes, the relief valves of LNG storage tanks are sized for a fire case.

Calculating the boil-off quantity that is expected is very difficult, if not impossible to estimate as it would depend on so many different factors. Therefore, designers may put emphasis onto the code requirements or back on the client as only they know how they will operate the tank and the type of cargos or liquefied product that could be produced and the time it will remain in the tank. Vent headers or flare stacks (to reduce environmental impacts) can be used to relocate the release away from the localised relief valves if the vapour evolution period (rollover event) is extended for a significant period of time, Sheats and Tennant (39) have stated that depending on the severity of the rollover, this could take several weeks. Flare systems are often preferred as they displace methane emissions with CO_2 emissions, which have a significantly lower global warming potential. Methane (the principal component of natural gas) is reported to be 20 times more harmful to the environment than carbon dioxide.

6. Rollover Prediction Models

The original rollover study reported the development of seven LNG rollover simulation models in 1983. Today, the LNG rollover simulation market is dominated by a few commercial proprietary software's that are based on the principles of the earlier models. This section provides an overview of the four main models on the market and their principal use.

Some LNG terminals around the world use rollover simulation models to predict the behaviour of LNG in storage tanks. Enagás use an LNG rollover simulation model to provide their operators with unloading strategies to manage cargos of different densities and simulate the stratification process once the LNG is stored.

A second motivating factor for utilising rollover prediction models is for operator training. Personnel with considerable experience feel comfortable in operating the plant with the indication of normal operating pressure and LNG stock temperature. However, newer operators do not have that experience to draw upon, and modelling and rollover simulation becomes an important tool to give confidence that the plant is being operated in a safe and efficient manner.

A growing trend for the use of model prediction software has been to manage the purposeful instigation of stratification as a stock management strategy. The advantage is to gain efficiencies during unloading operations by suppression of BOG evolution. This will be discussed further later in this section.

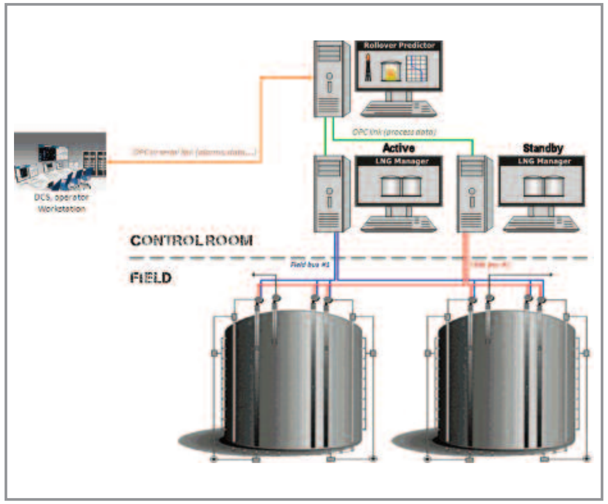


Figure 6.1 Typical Whessoe Tank gauging architecture

6.1 Whessoe Rollover Predictor

The LTD gauge monitors and detects a potential stratification of a stored LNG. But it doesn't provide the LNG terminal's operators with the evolution of the said stratification. Wärtsilä has developed, in collaboration with GDF Suez, the Whessoe Rollover Predictor software. The heart of the software, the calculation module, has been developed and validated in the Nantes, France 500 m³ LNG storage tank during a Gaz de France experimental campaign on its cryogenic testing station.

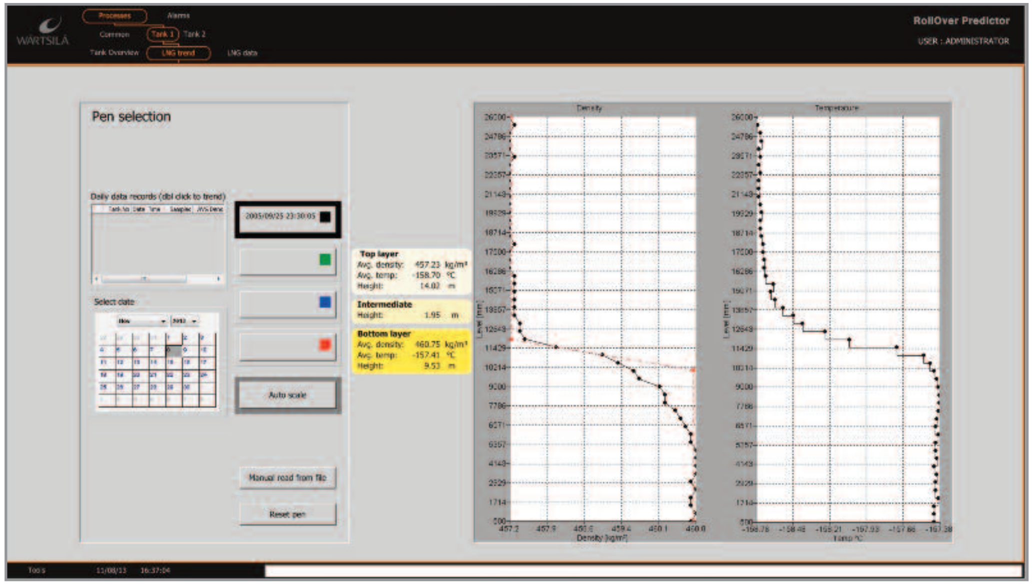


Figure 6.2
Density profiling overview

6. Rollover Prediction Models

The Whessoe Rollover Predictor software is directly connected to the Tank Data Acquisition platforms for an immediate processing of the LTD profiling data.

In case of layered LNG, the software analyses the density and temperature measurements from the LTD gauge (layer height, densities and temperatures). Other information is required such as the availability of safety equipment (flare, compressors, vents, valves, rupture disks) used in the operation of the LNG terminal. The connection of tanks vapour phases is also taken into account.

Based on the chemical compositions of the layers, densities, temperatures and safety equipment availability, the software determines an operational scenario that includes the evolution of each layer. This leads to predict also the evolution of the chemical composition for each LNG layer. These data feeds are recorded in order to be used at the next calculation step and thus increases the accuracy and the reliability of the predicted scenario.

The Whessoe Rollover Predictor predicts the occurrence of a rollover within the next 30 days, and provides the operator with:

- The tank where rollover is expected
- The remaining time to rollover
- The predicted boil-off gas level during rollover
- The predicted pressure rise during rollover

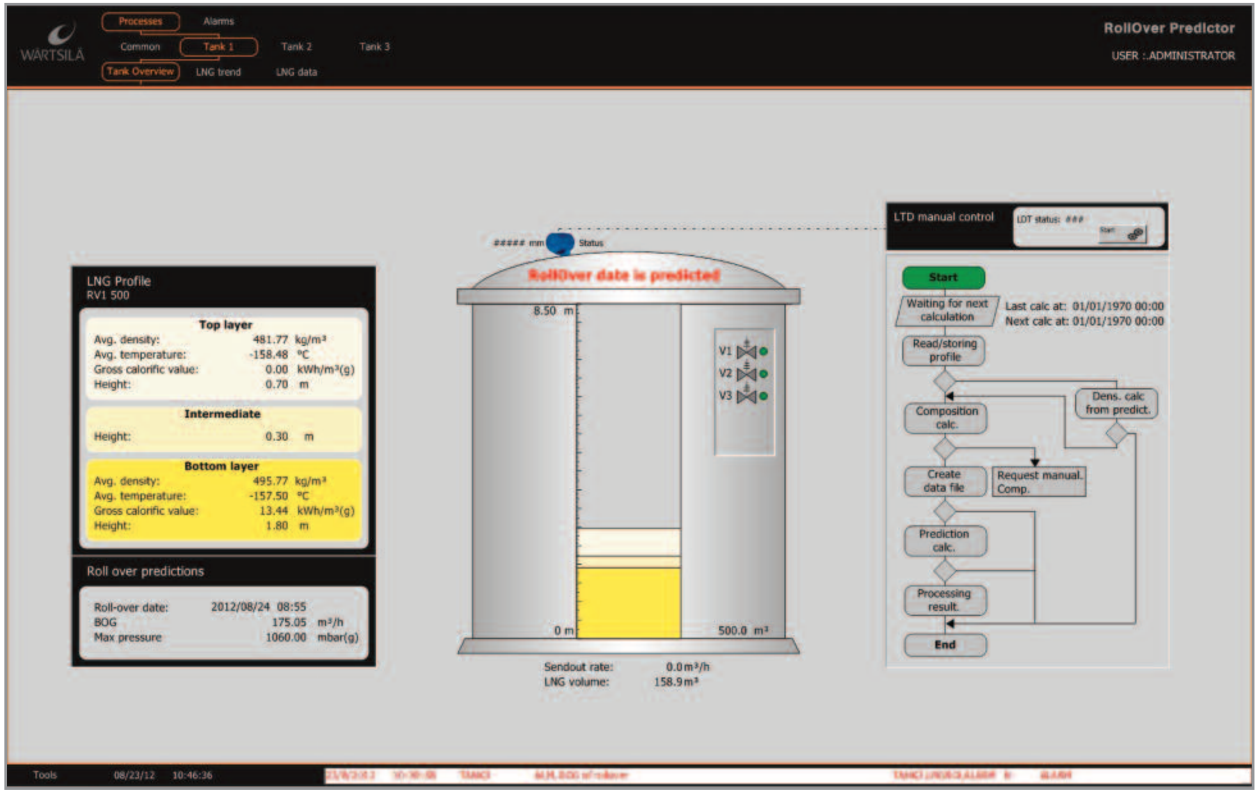


Figure 6.3 Tank overview screen in Rollover Predictor

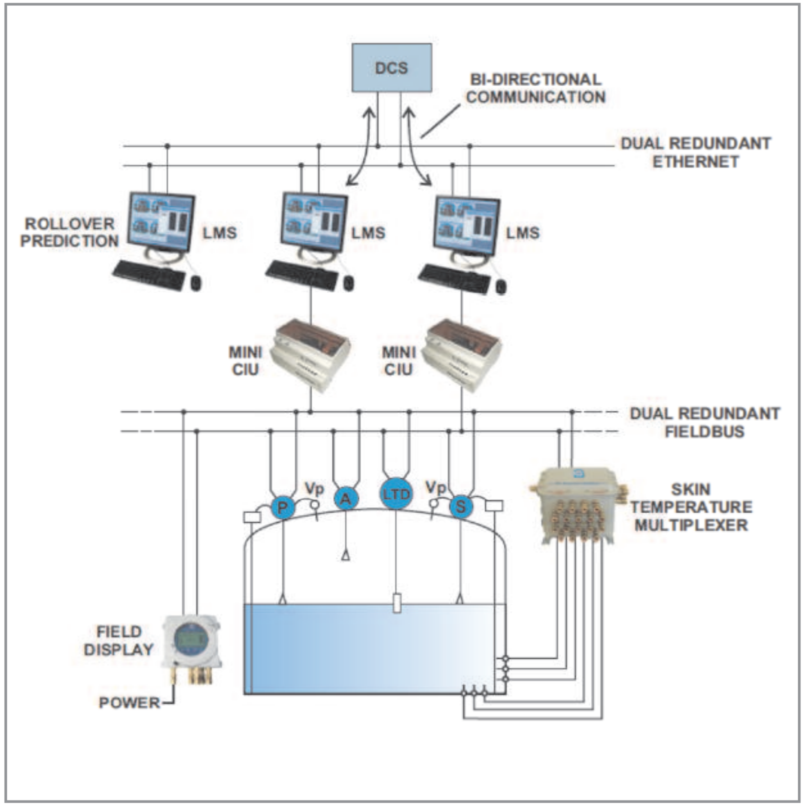


Figure 6.4 Instrumentation array as used by MHT rollover prediction Model

6.2 MHT Technology Ltd. Rollover Prediction Model

The Rollover Module developed by MHT Technology for predicting the behaviour of stratified LNG in storage tanks is based on the concept of lumped parameter model. It simplifies the spatial dependence of the system, compared with Computational Fluid Dynamics models. The module forms a part of an integrated LNG stock management system such as the one shown on Figure 6.4

Based on the given initial conditions, the model allows the user to visualise a number of process parameters and properties using screen such as the one shown on Figure 6.5, as well as number of graphs and tables.

The user can display the evolution of temperature, density, thickness of the stratified layers within a tank, as well as other parameters characterising the conditions inside the tank and inventory properties during rollover incubation. The novelty of the model comes from its ability to estimate heat and mass transfer coefficients from the real time level-temperature-density (LTD) profiles using the inverse method. These parameters have significant influence on heat and mass transfer between the liquid layers and consequently the onset of rollover and so their accurate prediction is of crucial importance.

The inverse method uses LTD profiles taken at two known instances in time. The lumped parameter model is solved iteratively varying the heat and mass transfer coefficients after each loop, until the predicted change in density will match the actual one between the two profiles within the defined accuracy. This way, starting with an initial estimate of the heat and mass transfer coefficients it is possible to obtain the adjusted values that best describe the given LNG tank at the time.

6. Rollover Prediction Models

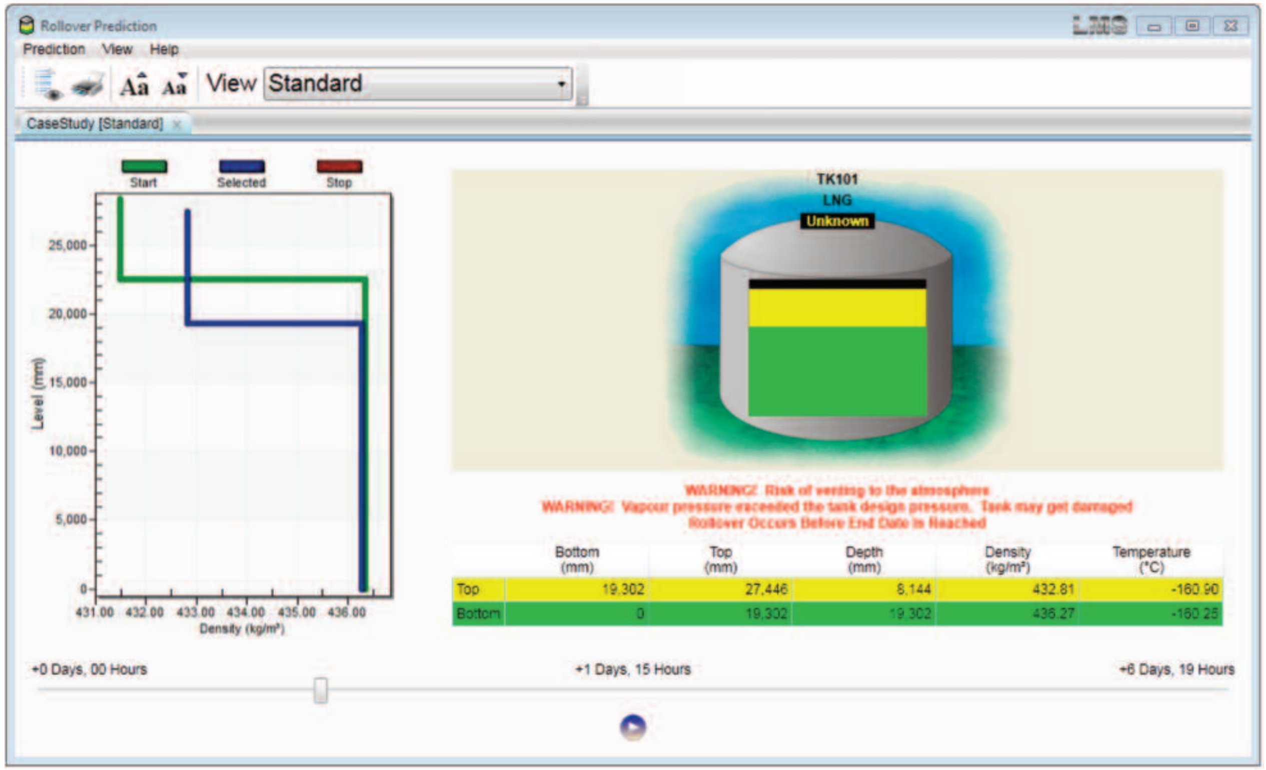


Figure 6.5 MHT Technology Rollover Module Standard View

The model accounts for all major tank operations such as external recirculation, emptying or filling, as well as processes such as flashing in the ullage vapour space. The output from the model calculations can be visualised (or displayed in tabulated form) and easily compared with different results for various operating conditions. This allows the operators of the plant to safely manage a tank in a stratified state if desired until it becomes necessary to take immediate actions to avoid rollover incident. The Rollover Module can annunciate the following alarms depending on the results of the performed simulation:

- The time to rollover event
- Warning: Risk of venting to atmosphere (in case the predicted peak vapour pressure exceeds the specified vent pressure)
- Warning: Risk of tank damage (in case the predicted peak vapour pressure exceeds the specified tank design pressure)

The module also recommends top or bottom filling depending on the density of the new LNG and the density of the LNG already in the tanks. It was validated against the two case studies described in detail in the open literature (La Spezia in Italy and Partington in UK) as well as the rollover incident which occurred at the Chattanooga peak-shaving terminal in US. Some of the principals of model operation were described by Deshpande (42).

6.3 LNG MASTER® GDF Suez

GDF Suez has developed a commercially decision-support software called LNG MASTER®, which predicts the behaviour of LNG in storage tanks. From the design to the operating phases of LNG facilities, the LNG MASTER® software predicts the behaviour of LNG during the operations that occur in LNG terminal storage tanks:

1. Unloading of LNG carriers into LNG storage tanks with assessment of tank filling consequences (boil-off gas generation, gas return flowrate from the terminal to the ship and LNG mixing).
2. Stratification evolution up to the rollover event with assessment of occurrence date and boil-off gas peak.
3. Ageing of homogeneous LNG with prediction of LNG composition changes, as well as Gross Calorific Value (GCV) and Wobbe Index changes.

4 Tank to tank transfer and LNG recycling within a tank.

5. Prediction of operating pressure changes on LNG behaviour.
6. LNG send-out operation to regasification unit (GCV and Wobbe index).

LNG MASTER® is intended both as a safety and optimisation tool for tank management operations in LNG storage sites (receiving terminals, liquefaction plants and peak shaving sites).

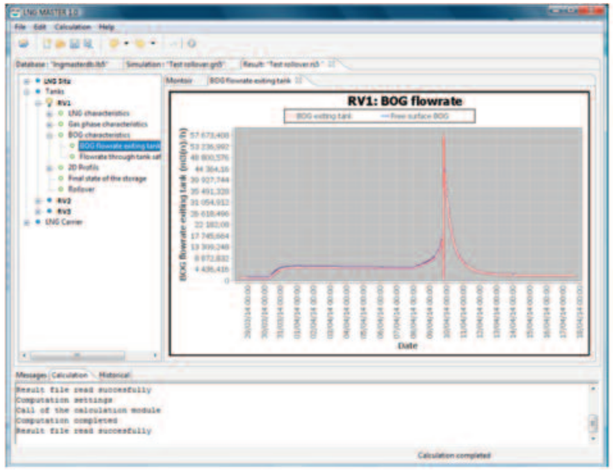


Figure 6.6 LNG MASTER® software

The LNG MASTER® software has been validated through a wide database developed from laboratory tests, a 500 m³ pilot tank LNG tests conducted in the past by GDF Suez on their LNG cryogenic testing station in Nantes (France) and on-field tests and operations follow-up at various LNG receiving terminals (Montoir-de-Bretagne Fos-sur-Mer and Fos-Cavaou and La Spezia). It mainly included tests on:

- LNG ageing and dynamic evaporation of stored LNG.
- Tank filling with complete LNG mixing or stratification formation.
- Stratification follow-up including rollover occurrence.

The LNG MASTER® software is based on published as well as in-house physical models which have been adapted to LNG product through these experimental and operational data. These models cover all the phenomena that could occur into LNG storages, among them:

- Hashemi & Wesson model for modelling LNG evaporation process at the LNG free surface that was originally developed for water but which has been adapted to LNG (5).
- Heat and mass transfer models across a thick interface in a stratified LNG storage comprising both double diffusive model based on J.S. Turner model (43) and interfacial entrainment model for modeling dynamics and progressive erosion of the thick interface based on Y. Zellouf model (44).
- Advanced dynamic tank filling model that is capable of simulating mixing of various LNG qualities during filling operations carried out in large industrial tanks with commonly used industrial filling devices. This model is also capable of predicting stratification formation when mixing is unachieved (45).

All the implemented models help the LNG operators in predicting the evolution of the mean density, temperature and concentration profiles as a function of time, as well as the instantaneous boil-off gas flow rate allowing them to optimise the handling of different LNG in the same tank during filling operations.

6. Rollover Prediction Models

LNG MASTER® can be applied to optimise the LNG unloading operation to storage tanks. It is well understood that a significant amount of gas is flashed off during the filling operation. One way of reducing the amount of gas produced during the unloading operation is to reduce the rate of filling, thus reducing flow of displaced vapour as the tank fills. Another solution is to optimise the tank's operating pressure in order to minimise gas production during tank filling. This is achieved by initially pre-cooling the tank heel before unloading by lowering the operating pressure. Changing the pressure draws off more BOG, thus lowering the temperature of the LNG. Prior to unloading, the operating pressure is increased above the normal operating pressure in order to suppress the amount of flashing for the unloaded LNG. Once tank filling has completed, the tank pressure is then progressively lowered to the normal operating level for storing LNG.

An alternative solution is to use a software prediction model such as LNG MASTER® to purposefully create a stratified condition as part of the unloading operation. By deliberately creating a stratification, in particular in the case of loading heavy cargo under light heel by bottom filling, the operator reduces BOG production rates during the filling operation, and reduces the BOG rate after tank filling during LNG holding condition. Uznanski and Versluijs (35) reported that the stratification method reduces the normal BOG rate by a factor of five. Other advantages for using this stratification method are to decrease electrical power consumption for BOG gas compression during LNG ageing, which reduces terminal operating costs. However, once such a stratification is formed, it needs to be managed safely particularly for the evolution of the stratification up to rollover.

Among the rollover mitigation methods available to the operator, tank emptying represents one of the most effective methods to safely manage stratifications. This method best suits LNG terminals with continuous or frequent exports of LNG. The emptying flow rate necessary to avoid rollover occurrence must be sufficient to completely empty the lower layer before its density equalises with that of the upper layer. LNG MASTER® can be used to calculate the critical emptying rate as shown in Figure 6.7.

Figure 6.7 shows the emptying rate curve giving the time necessary to empty the lower layer of a stratification at the prescribed emptying rate. The rollover time curve represents the rollover onset time at the given emptying rate. As the emptying rate increases, the rollover onset time decreases. At sufficiently high emptying rates, the two curves intersect. This intersection, defined by the critical onset time and the critical emptying flow rate, defines the critical point of stratification. The critical emptying flow rate of stratification is the flow rate at which the lower layer is entirely emptied just as

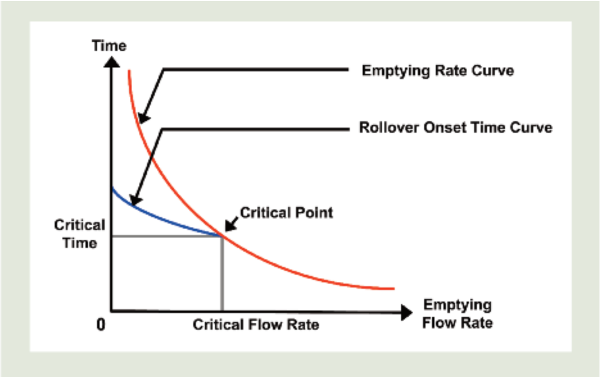


Figure 6.7 Stratification critical point

rollover occurs. Operating at an emptying flow rate above this critical flow rate ensures the withdrawal of the lower layer before rollover occurrence. In this way, the region in Figure 6.7 to the right of the emptying rate curve represents the safe operating zone of stratification. LNG MASTER® calculates the critical emptying flow rate with the site's operational constraints such as the number of pumps in tank to provide a strategy for operators to safely manage the stratification.

6.4 Computational Fluid Dynamics Model, Tokyo Gas

Tokyo Gas utilise a CFD 3D model, with the assistance of CFX, a general purpose CFD software for heat transfer and fluid flow analysis by ANSYS Inc., in order to improve safety, efficiency and reduce LNG storage costs. The CFD model is used for the simulation of LNG stratification and rollover for Tokyo Gas LNG importation terminals.

Koyama (46) evaluated the model's performance against measured values for an LNG importation terminal. Koyama's (46) results showed that the density contour (Figure 6.8) for lighter LNG received from bottom fill reaches the free surface driven by buoyancy, then spreads along the surface, forming a slow convective flow in the tank. These simulation results were then compared with the measured values recorded during a real unloading operation (Figure 6.8). Overall, a good correlation between simulation results and measured values was reported. Koyama (46) concluded that the initial density difference, the initial LNG depth, and the filling rate were directly related to any stratification that may have occurred post unload.

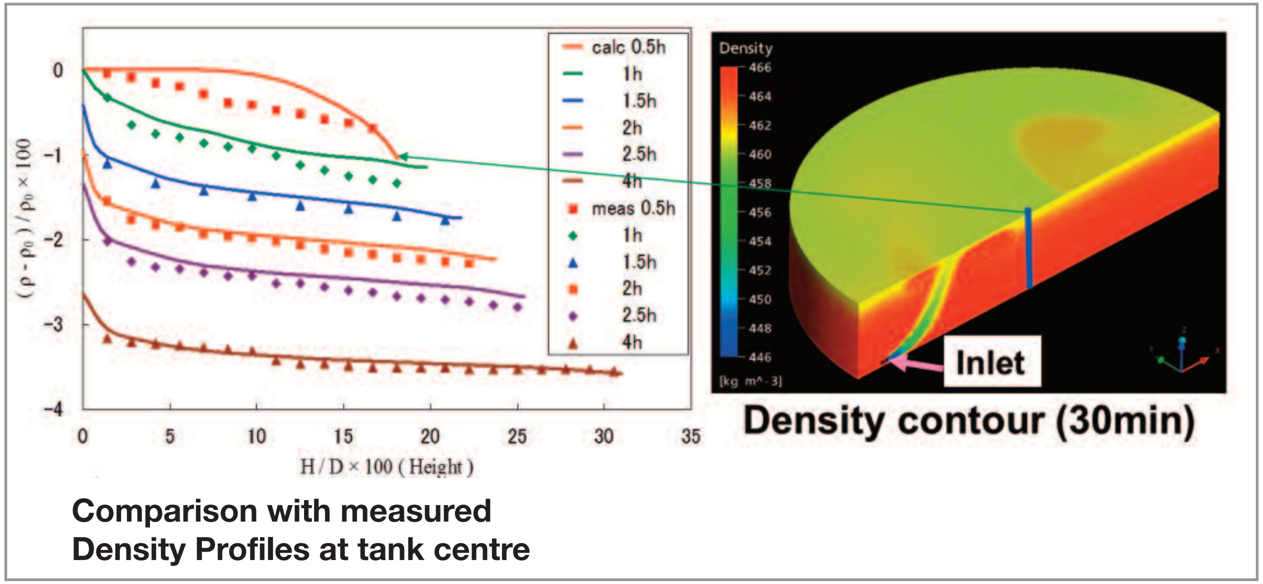


Figure 6.8 Comparison of density profiles simulation and measured

7. Conclusion

The GIIGNL Task Force have reviewed the phenomenon of LNG rollover within storage tanks. This document has presented the theory of the occurrence of stratification leading to rollover and the practical means of managing stratification, either to prevent rollover or to optimise BOG generation with the use of the right tools.

This document has summarised the occurrence of LNG rollover as the rapid release of LNG vapours from a storage tank that has become stratified. Stratification arises when two separate layers of LNG with different densities exist in a tank. The weathering effect enables the LNG densities to become approximately equal at which point the two cells rapidly mix. This rapid mixing causes large amounts of vapour to be released as part of an uncontrolled event that can have safety implications.

The Task Force conducted a worldwide survey and literature review for the collection of incident data. From the 24 rollover incidents reported, a conclusion was proposed that fewer incidents have been reported in recent years but rollover events are still occurring. This implies that the industry still has lessons to be learnt even if the events appear to be of a lesser impact than the events in the 1970's. This finding is of importance as the LNG industry is going through a growth phase with new operators and LNG being used in new processes. The principles of management stratification for these new processes are as yet not thoroughly developed.

Since the publication of the first GIIGNL rollover study in 1983 an increasing awareness of LNG stratification has resulted in a greater emphasis on the installation of advanced instrumentation. As a result, today LNG tanks are equipped with intelligent tank gauges that measure the key parameters such as level, temperature and density, with high accuracy and provide real time data to operators. The requirements for the design and operation of LNG plants are governed by international design codes which can specify the equipment that is necessary to manage LNG stratification.

An area of development within the study of LNG stratification is the growing trend for the use of model prediction software for stock management. These models are used for operator training and design purposes, and in some instances to manage the purposeful instigation of stratification as a means to optimise BOG generation.

This document also summarised the operating practices for different LNG terminals for how they manage LNG storage whilst preventing rollover.

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NORMA EUROPEA

Installazioni ed equipaggiamenti per il gas naturale liquefatto (GNL) - Progettazione delle installazioni di terra

UNI EN 1473

LUGLIO 2016

Installation and equipment for liquefied natural gas - Design of onshore installations

La norma definisce le linee guida per la progettazione, la costruzione e l'esercizio di tutte le installazioni di terra per il gas naturale liquefatto (GNL), comprese quelle per la liquefazione, lo stoccaggio, la gassificazione, il trasporto e il passaggio del GNL.
La norma è applicabile per i seguenti tipi di installazione:

- terminali di esportazione tra il limite di batteria definito di entrata del gas e i bracci di carico;
- terminali di ricezione tra i collettori della nave metaniera e il limite di batteria definito di uscita del gas;
- impianti di livellamento dei picchi, tra i limiti di batteria definiti di entrata e di uscita del gas.

Una breve descrizione di ogni installazione è riportata nell'appendice G.
La norma non si applica alle stazioni satellite.
Le stazioni satellite con capacità di stoccaggio minore di 200 t sono trattate nella UNI EN 13645

TESTO INGLESE

La presente norma è la versione ufficiale in lingua inglese della norma europea EN 1473 (edizione maggio 2016)

La presente norma sostituisce la UNI EN 1473:2007

ICS 75.200

UNI
ENTE ITALIANO
DI NORMAZIONE

PREMESSA NAZIONALE

La presente norma costituisce il recepimento, in lingua inglese, della norma europea EN 1473 (edizione maggio 2016), che assume così lo status di norma nazionale italiana.

La presente norma è stata elaborata sotto la competenza dell'ente federato all'UNI

CIG - Comitato Italiano Gas

La presente norma è stata ratificata dal Presidente dell'UNI ed è entrata a far parte del corpo normativo nazionale il 14 luglio 2016.

EUROPEAN STANDARD
NORME EUROPÉENNE
EUROPÄISCHE NORM

EN 1473

May 2016

ICS 75.200

Supersedes EN 1473:2007

English Version

Installation and equipment for liquefied natural gas - Design of onshore installations

Installations et équipements de gaz naturel liquéfié - Conception des installations terrestres

Anlagen und Ausrüstung für Flüssigerdgas - Auslegung von landseitigen Anlagen

This European Standard was approved by CEN on 4 March 2016.

CEN members are bound to comply with the CEN/CENELEC Internal Regulations which stipulate the conditions for giving this European Standard the status of a national standard without any alteration. Up-to-date lists and bibliographical references concerning such national standards may be obtained on application to the CEN-CENELEC Management Centre or to any CEN member.

This European Standard exists in three official versions (English, French, German). A version in any other language made by translation under the responsibility of a CEN member into its own language and notified to the CEN-CENELEC Management Centre has the same status as the official versions.

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EUROPEAN COMMITTEE FOR STANDARDIZATION
COMITÉ EUROPÉEN DE NORMALISATION
EUROPÄISCHES KOMITEE FÜR NORMUNG

CEN-CENELEC Management Centre: Avenue Marnix 17, B-1000 Brussels

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European foreword

This document (EN 1473:2016) has been prepared by Technical Committee CEN/TC 282 "Installation and equipment for LNG", the secretariat of which is held by AFNOR.

This European Standard shall be given the status of a national standard, either by publication of an identical text or by endorsement, at the latest by November 2016, and conflicting national standards shall be withdrawn at the latest by November 2016.

Attention is drawn to the possibility that some of the elements of this document may be the subject of patent rights. CEN [and/or CENELEC] shall not be held responsible for identifying any or all such patent rights.

This document supersedes EN 1473:2007.

In comparison with EN 1473:2007, the following changes have been made:

— the scope definition has been modified to cover interfaces and limits with floating solutions, plants refurbishing, renovation and expansion, and to better complement EN 14620;

— some requirements were revisited, such as tank containment types, new air vaporizer and sections that were subject to questions from the 2007 version;

— terms and definitions were adjusted to cope with new market development;

— the normative references were updated.

According to the CEN/CENELEC Internal Regulations, the national standards organizations of the following countries are bound to implement this European Standard: Austria, Belgium, Bulgaria, Croatia, Cyprus, Czech Republic, Denmark, Estonia, Finland, Former Yugoslav Republic of Macedonia, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Norway, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden, Switzerland, Turkey and the United Kingdom.

Introduction

The objective of this European Standard is to give functional guidelines for on-shore LNG installations. It recommends procedures and practices that will result in safe and environmentally acceptable design, construction and operation of LNG plants.

It need not be applied retrospectively, but application is recommended when major modifications of existing installations are being considered.

This standard is also recommended for debottlenecking, revamping and plant life extension in the limits that will be defined by the local Authorities. The appliance of the European Directives to the existing facilities is part of the limits to be defined together with the local Authorities.

In case of plant expansion, this European Standard is applicable for the new facilities. The application of these recommendations for the tie-ins and connections to the existing facilities will be defined by the local Authorities. The limits of such application should consider the practicality of such appliance. In the same way the limits of the European Directives appliance will be accurately defined with the local Authorities.

1 Scope

This European Standard gives guidelines for the design, construction and operation of all onshore liquefied natural gas (LNG) installations for the liquefaction, storage, vaporization, transfer and handling of LNG.

This European Standard is valid for plants with LNG storage at pressure lower than 0,5 barg and capacity above 200 t and for the following plant types:

— LNG liquefaction installations (plant), between the designated gas inlet boundary limit, and the outlet boundary limit which is usually the ship manifold and/or truck delivery station when applicable; feed gas can be from gas field, associated gas from oil field, piped gas from transportation grid or from renewables;

— LNG regasification installations (plant), between the ship manifold and the designated gas outlet boundary limit;

— peak-shaving plants, between designated gas inlet and outlet boundary limits;

— the fixed part of LNG bunkering station.

A short description of each of these installations is given in Annex G.

Floating solutions (FPSO, FSRU, SRV), whether off-shore or nearby shore, are not covered by this European Standard even if some concepts, principles or recommendations could be applied. However, in case of berthed FSRU with LNG transfer across the jetty, the following recommendations apply for the jetty and topside facilities if the jetty is located within 3 000 m from the shore line.

In case of FSU type solution, the on-shore part is covered by these standard recommendations.

This standard is not applicable for installations specifically referred or covered by other standards, e.g. LNG fuelling stations, LNG road or rail tankers and LNG bunkering vessels.

The plants with a storage inventory from 50 t up to 200 t with tanks at a pressure higher than 0,5 barg are covered by EN 13645.

2 Normative references

The following documents, in whole or in part, are normatively referenced in this document and are indispensable for its application. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

EN 809, *Pumps and pump units for liquids — Common safety requirements*

EN 1092-1, *Flanges and their joints — Circular flanges for pipes, valves, fittings and accessories, PN-designated — Part 1: Steel flanges*

EN 1127-1, *Explosive atmospheres — Explosion prevention and protection — Part 1: Basic concepts and methodology*

EN 1474 (all parts) *Installation and equipment for liquefied natural gas — Design and testing of loading/unloading arms*

EN 1514-1, *Flanges and their joints — Dimensions of gaskets for PN-designated flanges — Part 1: Non-metallic flat gaskets with or without inserts*

EN 1591 (all parts), *Flanges and their joints — Design rules for gasketed circular flange connections*

EN 1776, *Gas infrastructure — Gas measuring systems — Functional requirements*

EN 1991-1-2, *Eurocode 1: Actions on structures — Part 1-2: General actions — Actions on structures exposed to fire*

EN 1992-1-1, *Eurocode 2: Design of concrete structures — Part 1-1: General rules and rules for buildings*

EN 1992-1-2, *Eurocode 2: Design of concrete structures — Part 1-2: General rules — Structural fire design*

EN 1993-1-1, *Eurocode 3: Design of steel structures — Part 1-1: General rules and rules for buildings*

EN 1993-1-2, *Eurocode 3: Design of steel structures — Part 1-2: General rules — Structural fire design*

EN 1994-1-1, *Eurocode 4: Design of composite steel and concrete structures — Part 1-1: General rules and rules for buildings*

EN 1994-1-2, *Eurocode 4 — Design of composite steel and concrete structures — Part 1-2: General rules - Structural fire design*

EN 1997 (all parts), *Eurocode 7: Geotechnical design*

EN 1998-1, *Eurocode 8: Design of structures for earthquake resistance — Part 1: General rules, seismic actions and rules for buildings*

EN 1998-5, *Eurocode 8: Design of structures for earthquake resistance — Part 5: Foundations, retaining structures and geotechnical aspects*

EN 10204, *Metallic products — Types of inspection documents*

EN 12065, *Installations and equipment for liquefied natural gas — Testing of foam concentrates designed for generation of medium and high expansion foam and of extinguishing powders used on liquefied natural gas fires*

EN 12066, *Installations and equipment for liquefied natural gas — Testing of insulating linings for liquefied natural gas impounding areas*

EN 12162, *Liquid pumps - Safety requirements — Procedure for hydrostatic testing*

EN 12308, *Installations and equipment for LNG — Suitability testing of gaskets designed for flanged joints used on LNG piping*

EN 12434, *Cryogenic vessels — Cryogenic flexible hoses*

EN 12567, *Industrial valves — Isolating valves for LNG — Specification for suitability and appropriate verification tests*

EN 13445 (all parts), *Unfired pressure vessels*

EN 13480 (all parts), *Metallic industrial piping*

EN 14620-1:2006, *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 — Part 1: General*

EN 14620 (all parts), *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*

EN 60079-0, *Explosive atmospheres — Part 0: Equipment — General requirements (IEC 60079-0)*

EN 60079-1, *Explosive atmospheres — Part 1: Equipment protection by flameproof enclosures "d" (IEC 60079-1)*

EN 60079-2, *Explosive atmospheres — Part 2: Equipment protection by pressurized enclosure "p" (IEC 60079-2)*

EN 60079-5, *Explosive atmospheres — Part 5: Equipment protection by powder filling "q" (IEC 60079-5)*

EN 60079-6, *Explosive atmospheres — Part 6: Equipment protection by liquid immersion "o" (IEC 60079-6)*

EN 60079-7, *Explosive atmospheres — Part 7: Equipment protection by increased safety "e" (IEC 60079-7)*

EN 60079-10-1, *Explosive atmospheres — Part 10-1: Classification of areas — Explosive gas atmospheres (IEC 60079-10-1)*

EN 60079-10-2, *Explosive atmospheres — Part 10-2: Classification of areas — Explosive dust atmospheres (IEC 60079-10-2)*

EN 60079-11, *Explosive atmospheres — Part 11: Equipment protection by intrinsic safety "i" (IEC 60079-11)*

EN 60079-13, *Explosive atmospheres — Part 13: Equipment protection by pressurized room "p" (IEC 60079-13)*

EN 60079-14, *Explosive atmospheres — Part 14: Electrical installations design, selection and erection (IEC 60079-14)*

EN 60079-15, *Explosive atmospheres — Part 15: Equipment protection by type of protection "n" (IEC 60079-15)*

EN 60079-17, *Explosive atmospheres — Part 17: Electrical installations inspection and maintenance (IEC 60079-17)*

EN 60079-18, *Explosive atmospheres — Part 18: Equipment protection by encapsulation "m" (IEC 60079-18)*

EN 60079-19, *Explosive atmospheres — Part 19: Equipment repair, overhaul and reclamation (IEC 60079-19)*

EN 60079-20-1, *Explosive atmospheres — Part 20-1: Material characteristics for gas and vapour classification - Test methods and data (IEC 60079-20-1)*

EN 60079-25, *Explosive atmospheres — Part 25: Intrinsically safe electrical systems (IEC 60079-25)*

EN 60079-26, *Explosive atmospheres — Part 26: Equipment with Equipment Protection Level (EPL) Ga (IEC 60079-26)*

EN 60079-27, *Explosive atmospheres — Part 27: Fieldbus intrinsically safe concept (FISCO) (IEC 60079-27)*

EN 61508-1, *Functional safety of electrical/electronic/programmable electronic safety-related systems — Part 1: General requirements (IEC 61508-1)*

EN 62305 (all parts), *Protection against lightning (IEC 62305)*

EN ISO 1460, *Metallic coatings — Hot dip galvanized coatings on ferrous materials — Gravimetric determination of the mass per unit area (ISO 1460)*

EN ISO 1461, *Hot dip galvanized coatings on fabricated iron and steel articles — Specifications and test methods (ISO 1461)*

EN ISO 3452-1, *Non-destructive testing — Penetrant testing — Part 1: General principles (ISO 3452-1)*

EN ISO 9606-1, *Qualification testing of welders — Fusion welding — Part 1: Steels (ISO 9606-1)*

EN ISO 9712, *Non-destructive testing — Qualification and certification of NDT personnel (ISO 9712)*

EN ISO 10456, *Building materials and products — Hygrothermal properties —Tabulated design values and procedures for determining declared and design thermal values (ISO 10456)*

EN ISO 10497, *Testing of valves — Fire type-testing requirements (ISO 10497)*

EN ISO 12944 (all parts), *Paints and varnishes — Corrosion protection of steel structures by protective paint systems (ISO 12944)*

EN ISO 13709, *Centrifugal pumps for petroleum, petrochemical and natural gas industries (ISO 13709)*

EN ISO 15607, *Specification and qualification of welding procedures for metallic materials — General rules (ISO 15607)*

EN ISO 15609-1, *Specification and qualification of welding procedures for metallic materials — Welding procedure specification — Part 1: Arc welding (ISO 15609-1)*

EN ISO 15614-1, *Specification and qualification of welding procedures for metallic materials — Welding procedure test — Part 1: Arc and gas welding of steels and arc welding of nickel and nickel alloys (ISO 15614-1)*

EN ISO 16903, *Petroleum and natural gas industries — Characteristics of LNG, influencing the design, and material selection (ISO 16903)*

EN ISO 17636-1, *Non-destructive testing of welds — Radiographic testing — Part 1: X- and gamma-ray techniques with film (ISO 17636-1)*

EN ISO 17636-2, *Non-destructive testing of welds — Radiographic testing — Part 2: X- and gamma-ray techniques with digital detectors (ISO 17636-2)*

EN ISO 17637, *Non-destructive testing of welds — Visual testing of fusion-welded joints (ISO 17637)*

EN ISO 17640, *Non-destructive testing of welds — Ultrasonic testing — Techniques, testing levels, and assessment (ISO 17640)*

EN ISO 28460, *Petroleum and natural gas industries — Installation and equipment for liquefied natural gas — Ship-to-shore interface and port operations (ISO 28460)*

HD 60364-5-54, *Low-voltage electrical installations — Part 5-54: Selection and erection of electrical equipment — Earthing arrangements and protective conductors (IEC 60364-5-54)*

IEC/TR 60079-16, *Electrical apparatus for explosive gas atmospheres — Part 16: Artificial ventilation for the protection of analyser(s) houses*

3 Terms and definitions

For the purposes of this document, the following terms and definitions apply.

3.1
abnormal operation
operating conditions such as plant trip, the production and disposal of off-spec products and also operation with production equipment failed or on maintenance are modes of abnormal operation and are not accidental events

3.2
accidental event
event that arises from an uncontrolled or unplanned situation with safety and/or environmental consequences

3.3
boundary
property line on land or water inside which the operator/owner has full control and authority, or exclusive use

3.4
bund or bund wall
raised impermeable structure, able to withstand the static pressure and temperature of the spilled liquid, around the perimeter of an impounding area for the confinement of hydrocarbon spills, usually associated with storage areas

3.5
condensate
hydrocarbon liquids (liquid state at standard conditions) produced from primary separation of natural gas from a reservoir

Note 1 to entry: Natural gas condensates consist primarily of pentanes and heavier components, although quantities of propane and butane may be dissolved within the mixture.

3.6
primary container
container in continuous contact with LNG, i.e.:

— the cryogenic container of the single containment tank;

— the cryogenic container of the spherical tank;

— the cryogenic container of the double containment tank;

— the 9% Ni-steel self-supporting container;

— the concrete self-supporting container;

— the cryogenic membrane of the membrane tanks

3.7
secondary container
container in contact with LNG only in the event of a failure of the primary container i.e.:

— the bund walls for single and double containment tanks and spherical tanks;

— the outer container of full containment 9 % Ni-steel tanks, or membrane tanks or cryogenic concrete tanks

3.8
conventional onshore LNG terminal
LNG export or receiving terminal that is located on-shore and has a marine transfer facility for the loading or unloading of LNG carriers

Note 1 to entry: The transfer facility is located in a harbour or other coastal location and consists of a fixed structure, or wharf, capable of withstanding the berthing loads of a fully laden LNG carrier of a given specification and mooring the vessel safely alongside. The structure is connected to the shore by a trestle, tunnel or other means, facilitating the LNG transfer and ancillary services and providing safe access and egress for personnel performing maintenance or operational duties.

3.9
Operating Basis Earthquake
OBE
maximum earthquake for which no damage is sustained and restart and safe operation can continue

Note 1 to entry: This higher probability event would result in no commercial loss to the installation and public safety is assured.

3.10
Safe Shutdown Earthquake
SSE
maximum earthquake event for which the essential fail-safe functions and mechanisms are designed to be preserved

Note 1 to entry: Permanent damage can be expected of this lower probability event, but without the loss of overall integrity and containment. The installation would not remain in continuous service without a detailed examination and structural assessment at the ultimate limit state.

3.11
Emergency Shut Down (ESD) system
system that safely and effectively stops the whole plant or individual units to minimize incident escalation

3.12
fire area
an area of the plant delimited by physical boundaries or separations from other fire areas by boundaries such as site roads

Note 1 to entry: Multiple trains in a large plant are each a fire area. Different processing units each separated by plant roads are individual fire areas. A fire area is often self-defining in that it may be a single plant unit, a storage or utility area or a separate operating area such as a road tanker loading bay.

Note 2 to entry: The typical firewater ring main routeing often encloses each fire area.

Note 3 to entry: Pipe racks joining plant areas are not considered to affect fire area considerations.

3.13
fire zone
an area of the plant or process system within a fire area that requires to be isolated by ESDVs in the event of a fire to control and minimize the fire event, or in the event of a process upset or malfunction to minimize the extent of the process upset

3.14
flammable gases
gas or vapour which, when mixed with air in certain proportions, will form a combustible gas mixture

3.15
FLNG
floating liquefaction unit producing LNG, which will treat gas, process it to make LNG as a main production, store and unload LNG to a LNG carrier

3.16
FPSO
in LNG business, alternate word for FLNG

3.17
frequency
number of occurrences per unit of time

3.18
FSRU
floating storage regasification unit

3.19
FSU
floating storage unit

3.20
golden weld
weld that cannot be pressure tested due to its nature or location and that consequently will be subjected to a high level of non-destructive examination to prove that it is safe

3.21
hazard
property of a dangerous substance or physical situation with a potential for creating damage to human health and/or to environment[1)]

3.22
impounding area
area where spills from liquid hydrocarbon storage containers may be confined or controlled, close to the source of leakage

1) Refer to European Directive [Council Directive 2012/18/EC on the control of major-accident hazards involving dangerous substances].

3.23
impounding basin
container within or connected to an impounding area or spill collection area where liquid hydrocarbon spills can be collected and safely confined and controlled

3.24.1
SLS
serviceability limit state (SLS), which is determined on the basis of criteria applicable to functional capability or to durability properties under normal actions

3.24.2
ULS
ultimate limit state (ULS), which is determined on the basis of the risk of failure, large plastic displacements or strains comparable to failure under augmented actions

3.25
Liquefied Natural Gas
LNG
LNG (Liquefied Natural Gas) is defined in EN ISO 16903

3.26
LNG bunkering station
LNG station where LNG is brought by road, rail, sea, cryogenic pipe from a neighbouring terminal, and delivering LNG to ships using LNG as a marine fuel

Note 1 to entry: Delivery of the LNG can be done by road, sea or by fixed dispenser along the jetty.

3.27
LNG liquefaction plant
site at which natural gas coming by pipe from one or several gas producing fields or other sources is liquefied then stored for subsequent transport, normally by sea, to other destinations

Note 1 to entry: It has marine facilities for the transfer of LNG and can have loading stations for road, rail, barge or small LNG carriers.

3.28
LNG peak-shaving plant
plants connected to a gas network and that is used to balance the gas demands

Note 1 to entry: During the period of the year when gas demand is low, natural gas is liquefied and stored. LNG may be vaporized for short periods, when gas demand is high.

3.29
LNG receiving terminal
site where LNG carriers (ships) are unloaded, and where LNG is stored in tanks, vaporized and sent to the gas networks or gas consumers

Note 1 to entry: It has marine facilities for the transfer of LNG and can have loading stations for road, rail, barge or small LNG carriers.

3.30
LNG satellite plant
small LNG plants where LNG is supplied by road tankers, rail, barge or small LNG carriers

Note 1 to entry: LNG is stored in insulated pressure vessels, vaporized and sent to the network.

3.31
Natural Gas Liquid
NGL
liquid composed of light hydrocarbons (typically ethane through hexane plus) condensed from the natural gas prior to its liquefaction

3.32
normal operation
operation including intermittent operation such as ship loading or unloading, start-up, maintenance, planned shutdown and commissioning

3.33
operator/occupier
company responsible for the operation of the installation

3.34
owner
company responsible for the safe design and construction of the installation

3.35
PASQUILL atmospheric stability factors
factors that are determined as a function of the wind speed and solar radiation (see [1])

Note 1 to entry: The six factors are:

— A: extremely unstable;

— B: moderately unstable;

— C: lightly unstable;

— D: neutral;

— E: lightly stable;

— F: moderately stable.

3.36
probability
number in a scale from 0 to 1 which expresses the likelihood of an event occurrence

3.37
PSD (Process Shut Down) system
system that safely and effectively stops individual units within the plant for process reasons

3.38
risk
combination of the consequence and the frequency of a specific hazard occurring within a specified period under specified circumstances

3.39
Safety Management System
management process which defines and monitors the organizational structure, responsibilities, procedures, processes and resources for determining and implementing the major accident prevention policy[2)]

3.40
SIL
Safety Integrity Level required of a safety related system in terms of EN 61508

3.41
spill collection area
area at LNG production or transfer areas where leakages can be confined or controlled, often by the use of kerbing and/or controlled sloping of paved areas

3.42
SRV
shuttle regasification vessel

3.43
tank
equipment item in its entirety for the storage of LNG

Note 1 to entry: The different types of tank with pressure < 0,5 bar are described EN 14620 or are shown in Annex H.

3.44
transfer area
area containing a piping system where flammable liquids or gases are introduced into or removed from the plant or where piping connections are connected or disconnected routinely

3.45
validated model
mathematical model, the scientific basis of which is accepted to be sound and is proven to provide mathematical outputs to the relevant mathematical problem, and is shown to cover the full range of usage of the model and which has been calibrated or checked using realistic test data or results

3.46
vent stack
elevated vapour disposal system for the safe dispersion of vapour releases from the plant

Note 1 to entry: Reference [3] requires that the vent be designed with the assumption that it could become ignited and cause damage or injury due to thermal radiation.

4 Safety and environment

4.1 General

The design, procurement, construction and operation phases should all be implemented in accordance with the requirements of the Quality, Health, Safety and Environment management systems.

[2)] Refer to European Directive [Council Directive 2012/18/EC on the control of major-accident hazards involving dangerous substances].

Furthermore, each phase shall be controlled by an acceptable Safety Management System.

In case of plant expansion or debottlenecking, the environmental and safety impacts shall be appraised in accordance with the following recommendations. The potential consequences shall be analysed with regard to the current local regulations.

In case of revamping for life extension, the environmental and safety impacts shall be appraised in accordance with the following recommendations. The appliance of the current local regulations, and the extent of such appliance, shall be agreed upon with the local authorities.

In case of revamping without life extension and without debottlenecking, the principle of non-retroactivity shall prevail.

4.2 Environmental impact

4.2.1 Environmental Impact Assessment

During the feasibility study phase of the project, a preliminary Environmental Impact Assessment (EIA) shall be carried out for the proposed location in accordance with local regulations. Consideration should be given to formally recording the base line site environmental characteristics.

When the site has been selected, a detailed EIA shall be carried out.

All emissions from the plant, that is, solid, liquid (including water), and gaseous (including noxious odours) shall be identified and measures taken to ensure they will not be harmful to persons, property, animals or vegetation. This applies not only to normal, but also to accidental emissions.

During or prior to operation an effluent management procedure shall be established. The precautions for handling toxic materials shall be identified and be regularly updated by the operator/occupier.

The environmental impact due to construction and operation shall also be assessed and undesirable levels of activities shall be eliminated or minimized and restricted. The following checklist covers the main items:

— increased population, permanent and temporary;

— increased road, rail and ship traffic;

— increased noise levels, sudden and intermittent noise;

— increased vibration levels, sudden and intermittent;

— increased night working, effect of lights and their intermittent use;

— flaring, intermittent and/or continuous;

— warming or cooling of water.

4.2.2 Plant emissions

During the design, plans shall be developed to eliminate, minimize or render harmless emissions resulting from commissioning tests, operations and maintenance activities, and shall set targets for quantities and concentrations of pollutants in emissions.

4.2.3 Emission control

The following shall be safely controlled:

— combustion products;

- normal or accidental venting of gas;
- normal or accidental flaring of gas;
- disposal of acid gas removal solvent;
- disposal of spent mercury removal reactant (as the demercurization process is not regenerative, it is necessary to store and then treat the used absorbent mass or have it removed by a licensed waste disposal contractor);
- oily water condensed during dryer regeneration or from machines;
- in the case of water cooled equipment, hydrocarbon contamination of cooling water from leaking exchanger tubes;
- disposal of waste products (including waste oil and chlorinated organic compounds);
- vaporizer water;
- odourant chemicals.

4.2.4 Flare/venting philosophy

Plants are to be designed around the principle of no continuous flaring or venting. Provisions should be taken during design and operation to ensure that potential gas waste streams, wherever practically possible, are recovered and not routed to flare or vent during the normal operation of the plant.

4.2.5 Noise Control

The design of the plant shall consider the effects of noise on people within the plant exposed to noise and the effect of noise on any community surrounding the plant.

It is recommended that the noise design procedure of the plant should comply with ISO 15664.

4.2.6 External traffic routes

External traffic routes near to the LNG plant shall be listed in EIA, stating the volume and nature of present traffic and also any foreseeable development caused by the plant. In particular, the following shall be examined:

- overland routes (roads, railways);
- navigable routes (sea or river routes, canals);
- air routes and the proximity of airports and aerodromes.

4.2.7 Water discharge

The impact of water discharges shall be studied (temperature, currents, winds, etc).

4.3 Safety general

4.3.1 Safety philosophy approach

LNG installations shall be designed to provide generally accepted levels of risk (see Annex K) for life and property outside and inside the plant boundaries. In order to ensure this high level of safety in the LNG facilities and its surroundings, safety shall be considered throughout all the project development phases: engineering, construction, start-up, operation and decommissioning. In particular, hazard assessments, see 4.4, shall be carried out and the required safety measure implemented to ensure acceptable risk levels.

ISO/TS 16901 gives items to be covered by the QRA (in complement to here after subclause 4.3 items) and an approach to address the potential scenarios, their probability of occurrence and the consequence analysis.

4.3.2 Installation and its surrounding

4.3.2.1 Description of the installation

A functional description of the installation shall be written by plant area and/or by process function, for use in the safety assessment.

4.3.2.2 Site study

The site study shall include, where appropriate:

— a soil survey;

— a study of terrain to enable the dispersion of liquid and gas clouds to be assessed;

— a study of vegetation to enable, in particular, vegetation fire risks to be identified;

— a study of ground water tables;

— a study to identify sources of stray electrical currents (e.g. those emanating from high voltage power lines, railways);

— a study of the marine aquatic environment and marine access;

— a study of sea water quality and temperature;

— a study of tidal conditions;

— a study of shock waves and flooding (tsunami, failure of dams, etc.);

— a survey of the surrounding infrastructure (e.g. industrial sites, built up areas, communications);

— manoeuvring areas, safety distances whilst a LNG carrier is in transit within the port and at berth (see Clause 5 and EN ISO 28460).

The soil survey shall include:

— the geotechnical survey that will enable the geo-mechanical characteristics of the subsoil to be defined;

— the geological and tectonic investigation.

The geological characteristics of the region shall be investigated in sufficient detail to provide a clear understanding of the physical processes that formed the area, as well as the potential for the future seismic activity.

A more specific survey shall be done on the site and its vicinity to detect the presence of karst, gypsum, swelling clays, soluble salt deposits, soil liquefaction, mass movement etc. and their relative impact shall be evaluated.

Such phenomena are not allowed under the tank and/or equipment foundations unless it can be proved that appropriate measures have been undertaken to overcome the potential problems.

4.3.2.3 Climatology

The climatic study shall include the following points:

- wind strength and direction including frequency and strength of severe storms;
- temperatures;
- atmospheric stability;
- range and rate of change of barometric pressure;
- rainfall, snow, icing;
- corrosive characteristic of the air;
- risks of flooding;
- frequency of lightning strikes;
- relative humidity.

Climate change will be analysed as part of other investigations that may be required by the local conditions.

4.3.2.4 Seismology

An earthquake is defined by the horizontal and vertical accelerations of the ground. These accelerations are described in accordance with EN 1997 (all parts) and EN 1998 by:

- their frequency spectrum;
- their amplitude.

A site-specific earthquake analysis shall be performed. This shall include assessments of the risks of earthquake, tsunamis, landslides and volcanic activities. This analysis shall be presented in a Seismic Report where geological and seismic characteristics of the location of the facility and the surrounding region as well as geo-tectonic information shall be taken into account. As a conclusion, this report shall define all seismic parameters required for the design.

The size of the region to be investigated depends on the nature of the area around the site and the geological and tectonic conditions resulting from the soil survey, see 4.3.2.2. Generally, it is limited to a distance less than 320 km from the site, but in some instances it can include an entire tectonic province, larger than the above (see [22] for the principle). In this context, the investigations shall be extended down to a depth equal to at least twice the diameter of the structure or a coextensive circular foundation surrounding the same area as the structure.

A second level of analysis shall be made on the region within the 80 km from the site (regional seismo-tectonic investigation) with the aim of detecting the presence of any active geological faults (see [23]).

These investigations involve thorough research, review and evaluation of all historically reported earthquakes that have affected, or that could reasonably be expected to have affected the site.

In case of seismic faults in the immediate vicinity of the site, further investigations shall be conducted to estimate their possible activity. Faults for which inactivity cannot be confirmed are not allowed inside the site or within a distance to be determined from the soil morphology.

For details of the seismic investigations, surveys, analysis and format of response spectrum, reference is made to EN 1997 (all parts), EN 1998-1 and EN 1998-5.

The geological, tectonic and seismological studies help to establish:

— the safe shutdown earthquake (SSE);

— the operating basis earthquake (OBE).

These shall be established:

— probabilistically, as those that produce ground motions with the mean recurrence as a minimum interval of 5 000 years for the SSE and 475 years for the OBE, and/or,

— deterministically, assuming that earthquakes which are analogous to maximum historically known earthquakes are liable to occur in the future with an epicentre position which is the most severe with regard to its effects in terms of intensity on the site, while remaining compatible with geological and seismic data.

NOTE Both OBE and SSE define specific performance limits for seismic events of increasing severity for systems as defined in 4.5.2.2.

4.3.2.5 Location

During the feasibility study phase of the project site location assessments shall be carried out to ensure the suitability of the location options with regards to adjacent development. The assessment shall as a minimum consider the following:

— residential development;

— retail and leisure developments;

— sensitive developments (schools, hospitals, retirement homes, sports stadium, etc.);

— industrial development;

— transportation infrastructure.

When the site has been selected, a detailed site location assessment shall be carried out. The location assessment methodology and scope shall have regard for the proposed inventory of hazardous material contained on the plant and the presence and scale of adjacent existing and identified future developments, whilst being in conformance with local and national regulatory requirements.

It is recommended that:

— the assessment is updated on a regular basis and when major modifications or changes take place;

— the development around the plant is controlled to minimize the subsequent incompatible development.

Guidance for the probabilistic assessment acceptance criteria of site location are presented in Table K.2. These minimum acceptance criteria can be adopted in the event that no such criteria exist in the country where the plant is to be built.

4.4 Hazard assessment

4.4.1 General

A hazard assessment shall be carried out during the design of the plant and it is also recommended if a major modification or change takes place.

The following methodology and requirements see annexes that show examples of frequency ranges, classes of consequences and levels of risks. However, there is a variation in national and company acceptance criteria and the examples given in the informative Annexes I, J and K should be considered as minimum requirements. If more stringent local or national requirements exist they shall supersede these minimum requirements.

4.4.2 Assessment

4.4.2.1 Methodology

The methodology of the hazard assessment can be deterministic and/or probabilistic.

The deterministic approach consists of:

— list of potential hazards of external and internal origin;

— establishment of credible hazards;

— determination of the consequences;

— justification of the necessary safety improvement measures to limit the consequences.

The probabilistic approach consists of:

— list of potential hazards of external and internal origin;

— determination of the consequences of each hazard and their allocation into classes of consequence (an example is given in Annex J);

— collection/input of failure rate data;

— determination of the probability or frequency of each hazard;

— summation of frequency for all hazards within any one allotted consequence class and classify the frequency range for that consequence class (an example is given in Annex I);

— classification of hazards in accordance with their consequences class and frequency range, in order to determine the level of risk (an example is given in Annex K).

In the event that the risk determination indicates "Unacceptable Risk" levels (for example, risk level 3 of Annex K) the plant design or operating practices shall be altered and the assessment repeated until such time that no such "Unacceptable Risk" levels exist. In the event that the risk determination indicates normal, acceptable, risk levels (for example, risk level 1 of Annex K) no further action is considered necessary. For risk levels determined as requiring further reduction (for example risk level 2 of Annex K) additional safety measures should be considered to limit the risk to as low as reasonably practicable.

The hazard assessment can be based on conventional methods such as:

— hazard and operability study (HAZOP);

— failure mode effect analysis (FMEA);

— event tree method (ETM);

— fault tree method (FTM).

The hazard assessment procedure should be carried out during all stages of the design process. Implementation during the early stages of a project or design modification is recommended, this allows unacceptable designs to be improved in the most cost effective manner.

The probabilistic assessment minimum acceptance criteria given in Table K.1 are based on risk to personnel inside the plant boundary. Comparable categories for mass of hydrocarbon released are also given for guidance in Annex J. Alternative risk assessment methods can be used to assess the suitability of the plant design, typically business and hazardous incident escalation risk assessments. However, as a minimum personnel risk should be assessed and verified as acceptable during the plant design and following major modifications.

Risk analysis and its conclusions should not compromise good engineering practices.

4.4.2.2 Identification of hazards of external origin

Studies should be undertaken to identify hazards arising from outside the plant. Such hazards can be caused by:

— LNG carriers approaching the berth at excessive speed or angle;

— the possibility of collision with the jetty and/or LNG carrier at berth by heavy displacement vessels passing the berth (see [23]);

— the impact of projectiles and consequences of collision (ship, truck, plane, etc.);

— natural events (lightning, flooding, earthquakes, tidal bores, icebergs, tsunamis, etc.);

— ignition by high energy radio waves (see [25]);

— proximity of airport and/or flight-paths;

— a "domino effect" resulting from fires and/or explosions at adjacent premises;

— flammable, toxic or asphyxiant drifting gas clouds;

— permanent sources of ignition, such as high voltage power lines (corona effect);

— the proximity of the site to any external uncontrolled sources of ignition.

4.4.2.3 Identification of hazards of internal origin

4.4.2.3.1 Hazard arising from LNG

Loss of containment of LNG and of natural gas shall be considered for all items of equipment including the loading or unloading of road tankers or LNG carriers. To simplify the study, scenarios may be established.

These scenarios shall be defined in terms of:

— the probability or frequency of the hazard;

— the location of the leak;

- the nature of the fluid (LNG or gas, specifying the temperature);
- the rate and the duration of the leakage;
- the weather conditions (wind speed and direction, atmospheric stability, ambient temperature, relative humidity);
- the thermal properties and the topography of the ground (including any impounding area);
- the proximity of structural steelwork that may be susceptible to brittle failure due to low or cryogenic temperatures. Under certain circumstances when quantities of LNG have been introduced into water, over-pressurization without combustion has been known to occur; this phenomena is referred to as a Rapid Phase Transition (RPT). Refer to EN ISO 16903 and see [33] and [34].

In particular, the scenarios to be considered for various types of LNG tanks are listed in Table 1.

Table 1 — Scenario to be considered in the hazard assessment as function of tank types

Type of tank containment [d]	All metallic or only with metallic roof	Prestressed concrete (including reinforced concrete roof)
Single containment	[a]	
Double containment	[b]	
Full containment	[b]	[c]
In-ground	[b]	[c]

Scenarios to be considered:

[a] In case of collapse of the tank primary container, fire pool size corresponds to the impounding area.

[b] In case of collapse of the tank roof, the fire pool size corresponds to the secondary container.

[c] Roof collapse is not considered for these tank types except if it is specified in risk analysis.

[d] For definition, see 6.3.

4.4.2.3.2 Hazards which are not specific to LNG

The following causes of hazards that are not specific to LNG shall be considered:

- LPG and heavier hydrocarbon storage;
- simultaneous loadings on multi-product jetty;
- poor communication between ship and shore;
- traffic within the plant both during construction and operation;
- leakage of other hazardous substances, in particular flammable refrigerant;
- missiles originating from explosion;
- pressurised and steam raising equipment;
- fired heaters and boilers;

— rotating machinery;

— utilities, catalysts and chemicals (fuel oil, lubricating oils, methanol, etc.);

— pollutants found in the feed gas of liquefaction plants;

— electrical installations;

— harbour installations associated with the LNG plant;

— security issues (e.g. intrusion, sabotage);

— accidents during construction and maintenance;

— escalation of accidents.

4.4.2.4 Estimation of probabilities

The estimation of the probability associated with a given hazard, where utilised, shall be based on reliable data bases available in public domain and which are suitable for the LNG industry or on recognized methods as in 4.4.2.1 which will determine the frequency range for this hazard (see Annex I). The human factor shall be taken into account.

4.4.2.5 Estimation of consequences

4.4.2.5.1 General

The consequences of each scenario as defined above will depend on the characteristics of LNG and other phenomena described EN ISO 16903. For the hazardous characteristics of fluids other than LNG reference shall be made to their Material Safety Data Sheets.

4.4.2.5.2 Evaporation of spilled LNG

The phenomenon of instantaneous vaporization (flash, including possible aerosol formation) shall be taken into account.

Calculation of evaporation due to heat transfer shall be carried out using appropriate validated models.

The model shall take the following into account:

— LNG flow rate and duration;

— LNG composition;

— nature of the ground (thermal conductivity, specific heat, density, etc.);

— temperature of the ground or of the water;

— atmospheric conditions (ambient temperature, humidity, wind velocity);

— atmospheric stability or temperature gradient.

The model shall enable the following to be determined:

— pool propagation speed;

— wetted area in terms of time, and, in particular, the maximum wetted area;

— rate of evaporation in terms of time and, in particular, the maximum evaporation rate.

4.4.2.5.3 Atmospheric dispersion of LNG vapours

Calculation of the atmospheric dispersion of the cloud resulting from evaporation of LNG due to flashing and evaporation when in contact with the ground or water shall be carried out using appropriate validated models.

The determination of dispersion shall, as a minimum, take into account:

— the diameter of the evaporating pool;

— the evaporation rate;

— properties of the vapour;

— the nature of the ground (thermal conductivity, specific heat, density, etc.);

— the temperature of the ground or water;

— the atmospheric conditions (ambient temperature, humidity, wind speed);

— atmospheric stability or temperature gradient;

— site topography (surface roughness, etc.).

The atmospheric dispersion simulation shall be based on the combination of wind speed and atmospheric stability that can occur simultaneously and result in the longest predictable downwind dispersion distance that is exceeded less than 10 % of the time.

If no other information is available, the following atmospheric condition shall be considered: F (PASQUILL) atmospheric stability or equivalent temperature gradient, for a wind of 2 m/s and a relative humidity of 50 %.

The model shall enable the determination of:

— concentration contours;

— the distance to the lower flammability limit.

4.4.2.5.4 Jet release of natural gas or LNG

Calculation of atmospheric dispersion resulting from jet release shall be carried out using appropriate validated models to determine as minimum, the height or the distance reached by the jet and the concentration of gas at any given point.

Sources of jet releases should include releases from atmospheric safety valves, un-ignited flare and vents. Where appropriate it shall consider possible aerosol formation.

4.4.2.5.5 Over-pressure

The ignition of natural gas can create in certain circumstances (e.g. congested areas) an explosion generating an over-pressure wave. The flammability range of mixtures of gas and air is given in EN ISO 16903.

Recognized methods and models, for example the multi energy method (see [5]) and/or deflagration at constant speed method (see [6]) which have been validated can be used to calculate the over-pressure. This over-pressure should be specified where applicable for equipment, buildings and structures.

Where over-pressure on a tank, equipment item, building or structure is specified, it shall always be the incoming wave characteristics. In this case it may be assumed that a deflagrating explosion near the tank gives rise to an over-pressure that is applied, as a worst case assumption, to a half perimeter of the tank. The stresses in the tank caused by over pressure shall be determined by dynamic calculation. For the other structures, the stresses may be determined by static calculation.

The effect of potential over-pressure under elevated tank basis due to the ignition of a flammable mixture under the tank shall be considered.

The effects of wave reflection on the objects shall be the responsibility of the supplier.

4.4.2.5.6 Radiation

Calculation of the radiation caused by ignition of the vapour from a pool or jet of LNG or release of natural gas shall be carried out using appropriate validated models.

The model shall take the following into account:

— area of the pool fire or the dimensions of the flame;

— surface emissive power of the pool fire or of the flame (see EN ISO 16903);

— ambient temperature, wind speed and relative humidity.

The radiation calculation shall be based on the combination of wind speed and atmospheric conditions that can occur simultaneously and result in the highest predictable radiation that is exceeded less than 10 % percent of the time.

If no other information is available the following atmospheric condition shall be considered: a wind of 10 m/s and a relative humidity of 50 %.

The model shall enable the determination of the incident radiation at various distances and elevations.

4.4.3 Safety improvement

Where the hazard assessment demonstrates that threshold values defined in Annex A are exceeded or shows that the level of risk requires improvement (see Annex K), measures shall be taken, as for example:

— setting up a safety system which allows early detection of a leak and limitation of the consequences of ignitions (see 4.5 and Clause 13);

— increasing the dilution of the flammable cloud;

— elimination of potential sources of ignition inside a flammable cloud;

— reducing evaporation rates through minimization of heat transfer;

— reducing heat radiation by water curtains, deluge systems, foam or insulation;

— reducing vapour dispersion distance by warming the cloud by the use of foam or spraying;

— increasing spacing between equipment;

— protection of the installation against blast;

— alarm systems such as break-glass units, telephones, paging systems, closed circuit television and sirens.

4.5 Safety engineering during design and construction

4.5.1 Introduction

During engineering and construction, the safety shall be continuously scrutinized to guarantee the appropriate safety level with regard to the hazard assessment.

The safety management during design and construction shall include design considerations and continuous reviews as outlined respectively in 4.5.2 and 4.5.3.

4.5.2 Design

4.5.2.1 Common safety design features

4.5.2.1.1 Equipment and piping design for low temperature

Design pressures and temperatures of piping and equipment shall be selected to cover all anticipated operation and upset conditions. Suitable materials are listed in EN ISO 16903.

The stresses in pipe-work and equipment are affected by contraction/expansion phenomena due to temperature changes, the possibility of thermal shock and the method of insulation. Physical phenomena such as: liquid hammer, cavitation, flashing and two-phase flow shall be taken into consideration. The recommendations of Clause 9 are applicable. It is recommended that the main pipes are maintained in a cold condition, e.g. by circulating of LNG, line weathering.

4.5.2.1.2 Hazardous area classifications

All installations shall be subjected to a hazardous area analysis (see [12] and [13]). The terms of reference for such an analysis shall be laid down in accordance with EN 1127-1 and EN 60079-10-1 and EN 60079-10-2.

The form and the extent of each zone may differ slightly depending on the national or professional code used but shall be in line with the methodology set forward in EN 60079-10-1 and EN 60079-10-2. Consideration shall be given to EN ISO 28460 for the jetty, particularly for the hazardous zones generated when the LNG ship is alongside.

The selection of equipment for use in particular locations shall be determined from the hazardous zone classification of these locations in accordance with EN 1127-1 and EN/IEC series (parts 0 to 25).

4.5.2.1.3 Internal over-pressure protection

Safety devices shall be provided to cover all internal over-pressure risks including those due to fire.

It is recommended that the discharges from conventional safety devices (safety valves, relief valves) are routed to the flare/vent system or the storage tank. Tank and vaporiser safety valve releases, if not routed to the flare/vent systems, should be routed to a safe location as defined by hazard assessment.

If low and high pressure releases are routed to the same system, the risk of excessive back pressure shall be avoided. If excessive back-pressure could occur in low pressure release system due to high pressure release, then separate flare/vent systems may be considered for high and low pressure releases.

4.5.2.1.4 Emergency depressurizing

It is recommended that a depressurizing system is provided.

The intention of this measure is to:

— reduce the internal pressure;

— reduce the effect of leakage;

— avoid the risk of failure of LNG, hydrocarbon refrigerant or gas filled pressure vessels and piping from external radiation.

Devices for depressurizing high pressure equipment shall allow the pressure of one or more item of equipment to be reduced quickly (see [3]). These gases shall be sent to the flare system which shall be capable of handling the low temperatures generated during depressurizing.

Isolation valves, activated from a control room or other remote location or automatically, shall be provided so that the unit can be isolated into several sub-systems and where it is required to isolate sensitive equipment. This will make it possible to depressurize only one part of the plant, while limiting the entry of hydrocarbons into a fire containing zone.

4.5.2.1.5 Safety control system

A safety control system (see Clause 14) shall be provided to identify, inform and react appropriately to hazardous events. The safety control system shall be independent of the process control system and identify the hazard and, were appropriate, automatically bring the plant to safe conditions.

4.5.2.1.6 Inherent safety

The inherent safety protection shall be provided to:

— contain LNG spills within the fence, and minimize the credible scenarios where there could be the risk that vapour clouds spread beyond the plant periphery fence;

— minimize the possibility of a fire in any one area of the plant spreading to another area;

— minimize damage in the immediate area of a fire by the use of separation distances, minimizing the hydrocarbon inventory feeding a possible fire (by segregating the plant in different fire-zones, by isolation valves).

The inherent safety is to be encouraged over the use of complex systems.

Inherent safety protection measures are detailed in 13.1.

4.5.2.1.7 Passive fire and embrittlement protection

The passive fire and embrittlement protection shall 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.

Passive protection measures are detailed in 13.2.

4.5.2.1.8 Active fire protection

Equipment and or systems shall be provided to control and fight the emergency situations.

These equipment items/packages and systems are described in 13.6.

4.5.2.1.9 Additional LNG plant safety measures

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 probability of accidental and planned emissions of these fluids.

This shall be achieved by using a Safety Management System 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 with due consideration for commissioning, isolation and maintenance. Where flanges are used qualified gaskets as specified in EN 12308, suitable for the joint and service, shall be selected and, wherever possible, 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 and LPG;

— 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 (see [14]);

— isolation valves shall be fitted as close as possible to the nozzle, but outside the skirt, of process liquid outlets of pressure vessels containing flammable liquids. These isolation valves shall be capable of remote operation by push button in safe location or automatically by ESD (see Clause 14).

4.5.2.1.10 Impounding basin

The extent of the impounding basins and spillage collection channel for LNG and hydrocarbon pipe-systems and equipment shall be evaluated as a part of the hazard assessment (see 4.4). In general, it has been found that the collection of spill from interconnecting LNG and hydrocarbons piping, without branch, flanges or instrument connections, is not justified by hazard assessment.

If required, it shall be designed to accommodate potential leaks that will be identified in the hazard assessment.

Possible LNG and hydrocarbon spills should be drained into impounding basins, with foam generators or other measures for improved evaporation control.

Provisions for water recovery as given in 6.8.4 shall be applied.

4.5.2.2 Site specific: Seismic protection

The plant shall be designed to allow easy operational resumption after an OBE level earthquake (see OBE definition in Clause 3).

The following systems shall withstand actions resulting from higher earthquake (from OBE through to SSE levels):

— systems for which rupture can create a hazard for the plant;

— protection systems for which operation is required to keep a minimum safety level.

For this purpose, the plant systems and their components shall be classified on the basis of their importance (see Annex C). Such classification shall be analysed during the hazard assessment:

— **Class A:** systems which are vital for plant safety or protection systems for which operation is required to keep a minimum safety level. They shall remain operational for both OBE and SSE. The ESD system and LNG storage secondary container shall be in Class A.

— **Class B**: systems performing vital functions for the plant operation or systems for which rupture can create a hazard for the plant for which collapse could cause a major impact on the environment or could lead to additional hazard. These systems shall remain operational after OBE and shall keep their integrity in case of SSE. The primary container of all LNG tanks shall be in Class B.

— **Class C**: other systems. These systems shall remain operational after OBE and shall not fall on or impact other systems classes and components after SSE.

The systems include the related equipment, piping, valves, instrumentation, power supply and their supports. Structures shall be designed as for the class of the most stringent system component they are supporting.

The buildings that have a safety function, or which are normally manned, shall be designed to keep their integrity in case of SSE. Heating, ventilating and air conditioning shall be designed in order to fulfil the criteria of the classified systems which are located in the buildings.

4.5.3 Reviews

The reviews shall be organized through a strict application of an all-encompassing QA system (see Clause 15).

These reviews shall include as a minimum:

— Preliminary Hazard Analysis;

— layout review;

— HAZOP;

— maintenance and accessibility review;

— SIL review;

— pre-start-up review.

4.6 Safety during operation

4.6.1 General

The local regulations prevail but their appliance shall ensure that the items as listed in 4.6.2 and 4.6.3 are covered.

4.6.2 Preparation for plant operation

The preparation for plant operation shall include:

- personnel training, as outlined in Clause 17;
- development of plant operations, maintenance and inspection procedures;
- development of safety and security procedures, which integrate with the overall port emergency procedures and International Ship and Port facilities Security (ISPS) code, where relevant.

4.6.3 Safety during plant operation

Safety during the operational phase shall be achieved by the following features and measures:

- operation control, monitoring and safeguarding systems including work permits;
- reduction of uncontrolled sources of ignition;
- local and remote control of the firefighting system.

5 Jetties and marine facilities

5.1 General

This clause deals with the siting, engineering design, pre-operational training and safety requirements of the jetty and marine facilities.

5.2 Siting

The positioning of a jetty at a LNG marine terminal is a prime factor in determining the overall risk of the ship/shore transfer operation and a detailed study to determine the most acceptable position shall be undertaken at the conceptual stage of the project. Determination of what is acceptable in specific circumstances shall follow from an assessment of the actual risks posed by the operation of adjacent sites and harbour traffic.

Provisions described in EN ISO 28460 should be incorporated into jetty design and ship shore interface. See also other internationally recognized publications for additional requirements which may be relevant (such as [23] and [16]).

5.3 Engineering design

An appropriate standard for marine structures shall be used (see [22]) to determine the selection of relevant design parameters and methods of calculation to derive the resulting forces on the jetty structure. This should allow for soil conditions, plus the loads imposed on a LNG terminal jetty due to natural phenomena, such as winds, tides, waves currents, temperature variation, ice and earthquakes and those imposed by operational activities, such as berthing and mooring, cargo handling and vehicles used during construction, operation and maintenance.

A compatibility study should be undertaken to ensure the range of vessels that it is anticipated will berth at the terminal can safely do so (see EN ISO 28460).

Consideration within the design should be given to the possibility of LNG spills, particularly in the area adjacent to the transfer arms. This may be by provisions for containment of LNG spill and brittleness protection of carbon steel structural members, or by other appropriate measures.

A jetty operator room should be provided, having communications with both ship and terminal control rooms. It should contain controls for emergency shut down and release equipment for the LNG transfer system and jetty remote operated firefighting and vapour control equipment. Equipment should also be provided for monitoring sea and weather conditions and the ship's position and tension in the mooring lines.

A detection system shall be provided to give warning of any leakage of LNG or natural gas and also to give warning in the event of fire. Activation of this system shall automatically initiate an ESD of the ship-shore transfer system and give alarms in the jetty operator room, terminal control rooms and also be communicated to the ship by the means as recommended by EN ISO 28460. Marine transfer arms shall be used for the transfer of LNG between ship and shore. These shall be equipped with powered emergency release couplings according to EN 1474 (all parts).

Quick release mooring hooks shall be provided and the design of the release system shall be such that the operation of one switch, or failure of a single component, cannot release all moorings simultaneously.

5.4 Safety

Provision shall be made for rapid access and egress to the berth by emergency vehicles or vessels involved in firefighting, medical evacuation or pollution control.

On jetties relying on vehicular access it may be necessary to provide passing places.

Provision shall also be made for emergency escape routes from fire or liquid spill. From any point on the berth it should be possible to escape to a place of safety. This is most easily achieved by providing two independent routes to safety from the berth. These may include:

— additional walkways;

— provision of a manned standby boat(s).

Escape route shall be protected by water spray if found necessary by the hazard assessment.

Access to ship from jetty shall comply with requirements of EN ISO 28460.

It should not be possible for unauthorized persons to gain access to the jetty area, without being challenged, at any time (see [30]). Where security fences are used to achieve this consideration should be given to the general fire precautions and means of emergency egress. (See [24].)

6 Storage and retention systems

6.1 General

The design and construction of vertical, cylindrical, flat bottom LNG tanks are covered by EN 14620.

6.2 Types of tank

The types of tanks are characterized by their technologies, their secondary container (containment) and their foundations.

The main technologies are:

- the self-supporting 9 Ni-steel tank;
- the membrane tanks;
- the concrete tanks.

The types of containment are described in 6.3.

Other types could be accepted provided that their concept and safety could be proven appropriate for the functions as defined in 6.4.2 and the requirements in 6.4.1.

The tanks can be placed on the ground, or semi buried, or in ground or in pit. The raft of the tank can be supported by raised piles. The type of foundation depends on the result of the soil report and seismic study.

The different types of tanks are described in EN 14620 or shown in Annex H.

6.3 Types of containment

SINGLE CONTAINMENT

A single containment shall be designed to achieve the following functions:

- The primary container, or inner tank, shall contain the cryogenic liquid.
- This inner container could contain the product vapour or breathing nitrogen or could be duplicated by an outer shell that will contain the product vapour or breathing nitrogen.

In case of a leakage of the inner tank, the following scenarios shall be considered:

- release of cryogenic product;
- release of product vapours (also in case of leakage of the outer shell).

In case of single containments, the inner tank shall be surrounded by a bund wall to contain the possible product spillage.

DOUBLE CONTAINMENT

A double containment shall be designed to achieve the following functions:

- The primary container, or inner tank, shall contain the cryogenic liquid.
- The outer shell shall contain the product vapour or breathing nitrogen.
- The secondary container, or bund wall, shall contain the spilled LNG in case of leakage of the primary container.

In case of a leakage of the inner tank, the release of cryogenic product shall be considered.

In case of the outer shell leakage, the uncontrolled release of product vapour shall be considered.

FULL CONTAINMENT

A full containment shall be designed to achieve the following functions:

- The primary container, or inner tank, shall contain the cryogenic liquid.
- The secondary container, or outer tank, shall contain the product vapour and shall be able to contain the spilled LNG in case of leakage of the primary container.

The boil-off gas generated during the primary container leakage shall be contained within the secondary container with possibility of controlled venting though the pressure relief system. It is, however, acceptable that some gas leaks could occur through the secondary container in case of such accidental event.

6.4 Design principles

6.4.1 General requirements

The EN 14620 standard does not apply for storage tanks for which the design pressure is more than 500 mbarg. Higher pressure tanks shall meet the requirements of applicable standards or codes used for the design of the related type of pressure vessels[3].

Vertical, cylindrical, flat-bottomed steel LNG tanks shall meet the requirements of EN 14620.

The cylindrical cryogenic concrete tanks and spherical tanks for LNG shall be designed in accordance with the requirements from applicable standards or codes[3] and all requirements relating to LNG storage contained in this European Standard.

The LNG tanks shall be designed to:

— safely contain the liquid at cryogenic temperature;

— ensure gas tightness;

— permit the safe filling and removal of LNG;

— permit the boil off gas to be safely removed;

— prevent the ingress of air and moisture except as a last resort to prevent unacceptable vacuum conditions in the vapour space;

— minimize the rate of heat in leak, consistent with operational requirements and prevent frost heave;

— withstand the damage leading to loss of containment due to credible internal and external factors as defined in Clause 4;

— operate safely between the design maximum and minimum (vacuum) pressures;

— withstand the number of filling and emptying cycles and the number of cool down and warming operations which are planned during its design life.

6.4.2 Fluid tightness

The tank shall be gas and liquid tight in normal operation.

The degree of resistance to leakage required in the event of external overloads such as impact damage, thermal radiation and blasts shall be defined in the hazard assessment (see Clause 4).

LNG tightness of the primary container shall be ensured by a continuously welded plate, membrane or cryogenic concrete pre-stressed with cryogenic reinforcement.

LNG tightness of the secondary container shall be ensured by:

— continuously welded plate;

— concrete;

— compacted earth or sand provided LNG tightness can be ensured;

— other proven suitable material.

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3) E.g. EN 13445.

The outer envelope of the tank which is exposed to the atmosphere (metallic or concrete) shall be designed in such a way as to minimize water penetration, whether this is surface water, firewater, rainwater or atmospheric humidity. Moisture can introduce corrosion problems, deterioration of the insulation and of the concrete.

To contain liquid in case of LNG leakage in case of double or full containment (as defined by their functions in 6.3), the following requirements shall be applied for the secondary container.

— if made of metal, it shall be of cryogenic grade;

— if made of pre-stressed concrete, the temperature of the pre-stressed cables shall remain compatible with the strength of the maximum hydrostatic head. It is to be assumed for calculation that the temperature of the LNG is applied directly onto the internal face, including the insulation, if any;

— it shall withstand all operational and accidental loading conditions, as per EN 14620, and all hazardous conditions that are identified during the QRA (refer to 4.4). In case of damages to the secondary container, they shall be limited in size to prevent domino effect and loss of integrity of the primary container.

For a secondary concrete container where a rigid base/wall connection exists, a thermal protection system shall be foreseen to prevent uncontrolled cracking in this connection area. This thermal protection system shall be designed in accordance with EN 14620-1:2006, 7.1.11.

6.4.3 Tank connections

External connections shall be designed to accept loads imposed from the external piping and internal piping, if any.

The fluid and gas transfer pipes which penetrate the container shall satisfy the following requirements:

— penetrations shall not give rise to excessive heat input;

— where penetrations may be subject to rapid thermal contraction and expansion; if necessary the internal connections shall be strengthened and the external connections shall be designed to transmit external piping loads to a thermal expansion compensating system;

— there shall be no penetrations of the primary and secondary container base or walls;

— if needed, connections shall be provided for nitrogen into the annular space between the inner tank and the outer containment to enable air to be purged out before commissioning and LNG to be purged out after emptying for maintenance.

The absence of wall or base penetrations requires the use of submerged pumps. A platform and suitable lifting equipment on the roof shall be provided to allow pumps to be removed for maintenance.

The design shall prevent any siphoning effects.

6.4.4 Thermal insulation

Materials used for thermal insulation should be chosen from those defined in EN ISO 16903.

The installed insulation systems shall be free from contaminants which can corrode or otherwise damage the pressure-containing components with which they come into contact.[4)]

[4)] However, insulation used in the annular space or above a suspended deck (refer to definition in EN 14620) of self-supporting and concrete tanks, will be exposed to the boil-off gas.

Base insulation is installed beneath the primary container base to reduce heat transfer from the foundation and so that heating of the ground if required, to prevent frost heave, can be minimized.

Base insulation shall be designed and specified to be able to withstand any kind of action combinations as defined in EN 14620.

The thermal expansion of components shall be taken into account; therefore insulation installed outside the primary container, when it is made up of expanded perlite, can be protected from settling, for example, by glass wool padding which absorbs variations in the diameter of the primary container.

The thermal insulation of a membrane tank shall withstand the hydrostatic load.

Insulation of spherical tanks shall be at the outside the sphere and shall not be not exposed to any internal hydraulic or mechanical actions.

External insulation shall be protected from moisture by cladding and the installation of vapour barrier.

Exposed insulation shall be non-combustible.

The quality of insulation shall be such that no single point of the external envelope (excluding penetrating components) of the tank will remain at a temperature below 0 °C by an air temperature above or equal to 5 °C. The relevant conditions (atmospheric, soil, design, etc.) have to be taken into account for the thickness calculations.

In case of above ground storage tanks the minimum wind speed to be considered is 1,5 m/s.

6.4.5 Operating actions

LNG Tanks shall be capable of withstanding the combinations of actions as defined in EN 14620 and those resulting from changes in temperature and pressure during:

— initial cool down and warm up to ambient temperature;

— filling and emptying cycles.

The manufacturer shall indicate the maximum rate of temperature change that the tank can withstand during cool down and warm up operations.

For self-supporting steel tanks, the primary container shall be designed to withstand the maximum differential pressure which could occur during all operating phases. A system shall be provided to prevent lifting of the floor, if required.

6.5 General design rules

The structures of the tank shall be designed to withstand at least the combination of actions defined in EN 14620.

In addition, structures and structural elements shall:

— maintain their characteristics during normal conditions, with regard to degradation, displacement, settling and vibration;

— have adequate safety margin with regard to resisting fatigue failure;

— have adequate ductile and crack arresting properties and little sensitivity to local damage;

— provide simple stress paths with small stress concentrations;

— be suitable for condition monitoring, maintenance and repair.

The design shall minimize any degradation of the rebar or concrete to prevent reduction of the structural integrity of the tank during its design life.

6.6 Foundations

Foundations are designed to prevent differential settling higher than the permissible limit for the raft.

The design of the foundation shall be such that frost heave is avoided either by position of the base slab or by heating systems. If a heating system is used it shall be capable of in service repair or replacement and have 100 % redundancy.

Seismological analysis and the geotechnical analysis of the nature of the ground shall define the criteria for foundation design. Seismic insulators may be required in order to reduce the consequences of an earthquake. They shall be replaceable without decommissioning of the tank.

The raft can be raised, laid on the ground, semi-buried or in-ground.

When the raft is raised, the clearance left shall be sufficiently large to permit natural circulation of air which will maintain the lower face of the raft at a temperature not more than 5 °C cooler than atmospheric temperature. Gas detectors shall be installed in this bottom space to monitor the presence or accumulation of gas in case of leak. The effect of over-pressurization due to ignition of flammable mixtures shall be evaluated and mitigated.

Spherical tanks founded on solid rock do not need any heating device when the ground is properly drained and the space between the insulation jacket and the rock is properly ventilated or purged.

6.7 Operating instruments

6.7.1 General

Sufficient instrumentation is required to enable the tank to be commissioned, operated and decommissioned in a safe manner. Instrumentation will include at least the following:

— liquid level indicators and/or switches;

— pressure indicators and/or switches;

— temperature indicators and/or switches;

— density indicator, (except at peak shaving plants if provisions as defined in EN ISO 16903 are taken to prevent roll-over).

In general, the reliability of such measurements is to be ensured by the following minimum arrangements:

— instrumentation should be able to be maintained in normal operation of the tank;

— instrumentation related to safety and operation for which maintenance requires dismantling shall have sufficient redundancy;

— threshold detectors which have a safety function (pressure, LNG level, etc.) are to be independent of the measurement sequence;

— measurements and alarms shall be transmitted to appropriate control room(s);

— in earthquake areas, critical alarms, e.g. pressure and level, shall be transmitted by duplicated, diverse routes to the central control room.

6.7.2 Liquid level

High accuracy and independent level devices are recommended as the means for protection against overflow in preference to overflow-pipes.

The tank shall be fitted with instruments that enable the level of LNG to be monitored and that enable action to be taken. These instruments shall in particular allow:

— continuous measurement of the fluid level from at least two separate systems, of suitable reliability; each system shall include high level alarms and high high level alarms;

— detection of high high level based on instrumentation of suitable reliability which is independent of the above mentioned continuous measurements of level; detection shall initiate the ESD function for feed pumps and valves in feed and recirculation lines.

6.7.3 Pressure

The tank shall be fitted with instruments, permanently installed and properly located which enable the pressure to be monitored as follows:

— continuous pressure measurement;

— detection of too high pressure, by instrumentation which is independent of the continuous measurement;

— detection of too low pressure (vacuum) by instrumentation, which is independent of the continuous measurement. Following vacuum detection, the boil off compressors and pumps shall be stopped and if necessary, vacuum breaker gas injected under automatic control;

— if the insulated space is not in communication with the internal container, differential pressure sensors between the insulation space and the internal container or separate pressure sensors in the insulation space shall be installed.

6.7.4 Temperature

The tank shall be fitted with properly located, permanently installed instruments which enable the following monitoring:

— the liquid temperature at several depths; the vertical distance between two consecutive sensors shall not exceed two metres;

— the gaseous phase temperature;

— the wall and the bottom temperature of the primary container;

— the wall and the bottom temperature of the secondary container (unless the secondary container is a bund wall).

6.7.5 Density

The density of the LNG shall be monitored throughout the liquid depth.

6.8 Pressure and vacuum protection

6.8.1 General

The various reference flow rates which shall be taken into consideration for sizing the boil off circuit and the pressure relief valves are defined in Annex B. They are applicable to each tank taken individually. Sufficient margin shall be provided between the operating pressure and the design pressure of the tank to avoid unnecessary venting.

6.8.2 Origin of the boil off gas in the tank vapour space

Irrespective of the means for recovery of boil off gas which might exist elsewhere (e.g. reliquefaction, compression), the vapour space of the tank shall be connected to a flare/vent (see Clause 11), safety valve (6.7.3), or possibly a rupture disc (6.7.4) 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 flow-rate or return gas from carrier during loading;

— flash at filling;

— variations in atmospheric pressure (see B.7);

— vapourised LNG in desuperheaters;

— recirculation from a submerged pump;

— roll-over.

6.8.3 Pressure relief valves

The tank shall be fitted with over-pressure valves, plus one installed spare (n + 1 philosophy), directly relieving to the atmosphere except in cases where a vapour emission in an emergency leads to an unwanted situation as described in 4.5.2.1.3. In this case, the valves shall be linked to the flare network or vent system. The maximum flow to be discharged, at maximum operating pressure, is either the gas flow due to the heat input in the event of a fire or any likely combination of the following flow due to:

— evaporation due to heat input;

— displacement due to filling;

— flash at filling;

— variations in atmospheric pressure (see B.7);

— recirculation from a submerged pump;

— control valve(s) failure;

— roll-over, in case no other device is envisaged (for example see 6.7.4).

6.8.4 Rupture disc

If the calculation of the over-pressure valves or the flare/vent system does not take into account roll-over, a rupture disc or equivalent shall be installed whatever the other measures taken (for example, stock management policies, various filling lines).

A rupture disk can be used to protect the tank from over-pressure. This device, which should be regarded as a last resort, makes it possible to retain overall tank integrity by temporarily sacrificing gas tightness.

It shall be designed in such a way that:

— it can be replaced in operation following failure;

— fragments will not fall into the tank;

— fragments will not damage any other part of the tank.

Rupture of the disk shall cause all boil off gas compressors to trip automatically.

Means shall be provided to check disc integrity.

6.8.5 Vacuum

6.8.5.1 General

The tank shall be prevented from going into negative pressure beyond the permissible limit, by timely automatic shutdown of pumps and compressors, gas or nitrogen injection and by air vacuum breaker valves.

As introduction of air can bring about a flammable mixture, the air vacuum breaker valves shall act only as a last resort in order to prevent permanent damage to the tank.

6.8.5.2 Gas injection system

Gas may be injected under automatic control to minimize low pressure in tank pressure (see 6.7.3).

6.8.5.3 Vacuum relief valves

The tank shall be fitted with vacuum relief valves, plus one installed spare (n + 1 philosophy). The flow to be admitted at maximum negative pressure shall be 110 % the flow that is required to mitigate any likely combination of the following causes:

— variation of the atmospheric pressure;

— pump suction;

— boil off gas compressor suction;

— LNG injection into the vapour space.

6.9 Bund walls and impounding area for single and double containment

6.9.1 General

The rules of this subclause do not apply to full containment types provided that they are fully in compliance with EN 14620 and that the secondary container achieves the requirements of 6.4.2.

6.9.2 Impounding area for single containment

For cylindrical single containment and for spherical tanks, an impounding area is required to collect and contain any LNG spillage.

For these tanks if installed in an excavation, the ground could act as the impounding area provided that its properties are suitable (see 6.4.2 and 4.4.2.5).

The impounding areas of two tanks may be combined. The design of the impounding shall ensure that the accident shall not cause damage to the adjacent tank.

6.9.3 Impounding area for double containment

For double containment, the bund walls shall be located within 6 m from the outer envelope of the primary container.

6.9.4 Materials

Retention system materials shall be impermeable to LNG. The thermal conductivity of the material affects the rate of evaporation following a spill. The need to insulate the impounding area and impounding basins (see 6.8.5) will depend on the results of the hazard assessment (see 4.4). Insulation coating of such systems shall be designed in accordance with EN ISO 16903 and EN 12066.

The bottom of the impounding area should not be made up of gravel as heat transfer properties would increase vaporization. Every effort shall be made to keep the bottom free from any vegetation that may pose a fire hazard.

6.9.5 Recovery of water

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 the tank.

The water shall drain to an impounding basin within the impounding area and be removed by pumping. The pump shall be inhibited from starting should LNG leakage be detected.

6.9.6 Retention capacity

The impounding area within the bund walls shall be large enough to contain at least 110 % of the gross liquid capacity of the biggest tank.

The operator/occupier shall demonstrate that the wall will not be overtopped, even in case of the most severe failure identified by hazard assessment.

When the edges of the bund walls are more than 15 m away from the tank, consideration shall be given to the installation of an impounding basin within the impounding area. The needs of such will be identified in the hazard assessment in 4.4. The basin shall be capable of collecting leaks from LNG pipework including the overflow pipe (if any) within the impounding area. The following design principles apply:

— the capacity shall be greater than the amount of liquid which would be spilled by breakage of the pipe 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.

The location of the impounding basin with respect to adjacent equipment shall have regard to the hazard assessment and heat flux level given in Annex A.

In addition, means for limiting evaporation and reducing the rate of burning of ignited spills and consequences should be considered.

6.10 Safety equipment

6.10.1 Anti-roll-over devices

In order to avoid roll-over at least the following measures shall be taken:

— filling systems as defined in 6.10.2;

— a recirculation system;

— monitor boil off rate;

— temperature/ density measurements throughout LNG depth.

Other operational preventive measures may be used, such as:

— avoiding storing significantly different qualities of LNG in the same tank;

— appropriate filling procedure considering the respective densities of the LNG;

— specific processing for LNG which contain a nitrogen molar fraction higher than 1 %;

— cycle tank usage to prevent stagnation of LNG inventories.

The design of the tank may be based on tank LNG behaviour simulation validated software which integrate filling and emptying phases. They may be used to predict stratification occurrences, to estimate consequences and to evaluate the means to avoid or to manage them.

6.10.2 Protection against lightning

The tank shall be protected from lightning in accordance with 12.2.

6.10.3 Reliability and monitoring of structure

6.10.3.1 Reliability

LNG tanks require a design that ensures that changes in the structural condition of the tank are slow and limited, on one hand, and permits monitoring of representative parameters of the tank condition, on the other.

The level of reliability which it is necessary to achieve as required by Clause 4 can lead to the back-up of certain components of the structure. For example, the use of a primary container and a secondary container.

6.10.3.2 Monitoring of structure

Devices for monitoring the general condition of the structure, including the foundation, shall be designed in such a way as to leave sufficient time for action if anomalies are detected.

The monitored values shall be interpreted in terms of pre-defined:

— normal values;

— alarm values;

— critical values.

The parameters which are required for the monitoring of the general condition of the structure are stated below.

6.10.3.3 Temperature sensors

Three sets of temperature sensors are required:

- on the outer skin of the primary container wall and bottom, to monitor cool down and warm up, except for membrane tanks;
- on the warm side of the insulation (wall and bottom) to detect any leakage and to monitor any deterioration of the insulation due for example to settling;
- on the outer surface of concrete raft or point of support for all types of tanks to monitor the temperature gradient.

The outer surface of concrete walls of outer containers in case of full containment may be provided with temperature monitoring.

Plots from all sensors shall be recorded in the appropriate control room(s) and any confirmation of leakage shall sound an alarm. The covering of sensors shall be sufficient to ensure that any leakage is detected and the temperature gradient is monitored.

6.10.3.4 Heating system control

In the case of tanks that have a heating system, temperature and consumption of power by the system shall be continuously recorded.

6.10.3.5 Settling monitoring

Monitoring of foundation settling shall be carried out during hydrotest and is recommended during operation.

6.10.3.6 Primary container leak detection

For all tanks where the insulation space is not in communication with the primary container, a system shall be provided for nitrogen circulation within the insulation space. Monitoring of the tightness of the primary container is then possible by detection of hydrocarbons in the nitrogen purge.

6.10.3.7 Tank external leak and fire detection

The kind of detectors to be used and their location are defined in Clause 13.

6.11 Tank piping

6.11.1 Cool down piping

A system for cool down shall be provided to prevent cold liquid from falling onto the bottom of a warm tank. It can terminate for example, in a spray nozzle or a perforated ring.

6.11.2 Filling piping

Top and bottom filling connections shall be provided. The bottom filling connection shall be provided with a device to allow mixing of the tank contents.

6.12 Distance between tanks

The distance between tanks shall be determined in accordance with the hazard assessment (see 4.4) but shall not be less than the minimum criteria given in 13.1.2.

6.13 Commissioning and decommissioning

The devices which will be used for commissioning and decommissioning operations shall be defined at the design stage:

— drain circuits shall be designed in such a way as to allow inerting and complete drying, of the insulation space in particular. Provision shall be made for the taking of samples for monitoring these parameters;

— in case the insulation is directly in contact with the gas volume of the tank, provision shall be taken for purging and inerting this space;

— cool down piping shall be designed as given in 6.10.1;

— the self-supporting primary container shall be fitted with a sufficient number of temperature sensors in order to provide accurate monitoring of gradients in space and time (see 6.7.3 and 6.10.3.3);

— pressure balancing devices shall be provided for protecting the primary container against instances of excessive negative pressure (see 6.7.3). The actual differential pressure shall be monitored during commissioning and decommissioning.

6.14 Testing

Testing shall comply with EN 14620.

7 LNG pumps

7.1 General

This clause covers the minimum requirements for specifying, design, manufacturing, testing, installing, operating and maintenance of centrifugal pumps used for LNG services.

Safety technical demands described in EN 809 as well as safety measures on the LNG plant described in 4.5, are required for centrifugal pumps for LNG, designed, installed and operated in the plant areas.

Design, manufacturing and testing requirements are defined in the following standards:

— EN ISO 9906;

— EN 12162;

— EN ISO 13709.

The additional requirements for LNG pumps are included in Annex D.

When the pump electric motor is supplied with a frequency inverter to adjust the speed of the pump during operation, the following standards should be used:

— EN 61800;

— EN 12483.

In this case, a study of electromagnetic compatibility and harmonic influence on the supply network shall be performed. These requirements should be taken to reduce the consequences of the use of frequency inverters.

7.2 Materials

Materials should be chosen from the materials recommended for LNG use as defined in EN ISO 16903.

Care shall be taken for compatibility between material classes.

Other materials may be used provided supplier can demonstrate their suitability.

7.3 Specific requirements

Each pump shall be individually valved in order to enable isolation, draining and purging for maintenance.

In case of pumps running in parallel, a check valve shall be installed. Provision shall be made to avoid hydraulic hammer from this check valve.

Provisions should be made to ensure that the pump would not be damaged due to low flow.

For "pot" (or "can") or "column" mounted pumps, provision shall be made to ensure an adequate venting of the gas pockets.

Condition monitoring should be installed on the pump.

The pot (or can) mounted pumps shall have provision for purging, draining and isolation. If the pump is installed in a pit, provision shall be made to ensure that the drain and vent valves can be operated during pump decommissioning.

7.4 Inspection and testing

A specific inspection and testing programme shall be implemented in accordance with the Annex D to demonstrate the pump operability throughout the full operating conditions.

The testing load cases shall be defined with regard to these operating conditions.

8 Vaporization of LNG

8.1 General requirements

8.1.1 Function

The function of a vaporiser is to vaporise and heat the LNG in order to send out the natural gas into the transmission network at a temperature above the hydrocarbon dew point and not lower than 0 °C.

8.1.2 Materials

Materials can be chosen from the materials for LNG listed in EN ISO 16903. As vaporisers are also in contact with a heating fluid, one of two arrangements, shall be adopted:

— either the material is compatible (no corrosion or erosion) with the heating fluid for which the characteristics shall be properly specified beforehand;

— or a protective coating is applied onto parts in contact with the heating fluid.

Care shall be taken with compatibility of materials: it should be noted, for example, that tubes of open rack- vaporisers are usually made of aluminium alloy while LNG pipe-work is made of austenitic stainless steel.

A transient analysis shall be performed in order to check the risk of cold propagation on piping downstream the vaporiser (see E.2.6 for monitoring and control).

8.1.3 Protective coating

When a protective coating (paint, metal spraying, galvanization, etc.) is applied in order to protect the vaporiser against chemical or physical attack from the heating fluid, that coating shall be stable both at the temperature of the LNG and at the maximum temperature of the heating fluid.

The protective coating can gradually erode and corrode. The maximum rate of loss of the coating shall be specified taking due account of the operating of conditions (flow velocities, temperature, composition, duration of utilization).

The manufacturer of a vaporiser using surface coating shall provide means for the coating to be repaired or replaced.

In all cases, the manufacturer shall provide a detailed description of the maintenance of the coating.

8.1.4 Natural gas circuits

At the vaporiser outlet, piping materials are to be chosen in terms of the lowest temperature that might occur. This depends on the following:

— the set point of the temperature switch which automatically closes the isolation valves;

— the time required to close the LNG valve;

— thermal transients before temperature stabilization;

— temperature drop due to expansion of the gas to a lower pressure.

Materials shall be:

— austenitic stainless steel up to isolation valves which close in the event of gas temperature below the specified threshold;

— suitable for the lowest temperature which can occur downstream of the isolation valve before it can be shut.

8.1.5 Stability/vibration

Vaporisers shall operate in a stable condition without any vibration for the specified operating range.

8.1.6 Safety relief valves

To avoid over-pressure, any vaporisers that could be isolated (blocked in) shall have at least one safety relief valve. The flow-rate required for the relief valve shall be calculated using the following assumptions:

— the vaporization section is filled with LNG at working temperature;

— the isolation valves of the section are closed and assumed to have a tight shut-off;

— the heating system (heating fluid, bath, etc.) remains in service at maximum power (at maximum possible temperature and at maximum flow rate for the heating medium);

— unless the shut-in overall heat transfer coefficient is known, the heat transfer coefficient shall be based on clean operation (i.e. zero fouling resistance) and the rated LNG flow.

The safety relief valves may discharge directly to the atmosphere to a safe location. If this is not possible, the discharge of the safety relief valves shall be routed to the flare or to the vent.

8.1.7 Performance data

The nominal values of the performance data of the vaporisers, which are listed below, shall be ensured by the manufacturer:

— minimum and maximum flow;

— minimum outlet temperature;

— maximum pressure drop;

— maximum fuel gas flow or maximum heating medium flow and power requirement;

— minimum pressure for rated duty.

8.2 Design conditions

The vaporiser shall be designed, as a minimum, to withstand the simultaneous design conditions defined in Table 2.

Table 2 — Simultaneous design conditions

	Permanent and variable conditions to be combined						
Design conditions	**Weight**	**Pressure test**	**Operating pressure**	**Cooling stresses**	**Thermal stresses**	**Wind**	**OBE**
Test	1	1	-	-	-	1	-
Cooling	1	-	1	1	-	1	-
Normal operation	1	-	1	-	1	1	1

8.3 Vaporiser requirements

Specific requirements for some of the vaporiser designs currently in common use are defined in Annex E.

9 Pipe-work

9.1 General

The purpose of this clause is to highlight some features of pipe-work design that are particularly relevant to LNG facilities.

9.2 Piping systems

9.2.1 Piping system scope

The main piping systems of an LNG plant include:

— main process systems;

— auxiliary process systems;

— utility systems;

— fire protection systems.

9.2.2 The main process systems

These will depend on the type of plant but can include:

- high pressure natural gas system, to or from the natural gas transmission network;
- low and high pressure LNG systems;
- LNG ship loading/unloading systems, between the ship and the storage tanks; this system terminates at the connecting flanges to the transfer arms;
- boil off gas system, including discharge to the flare/vent and vapour return to the ship;
- refrigerant systems, between the liquefaction compressor, the heat exchangers and any refrigerant storage.

9.2.3 Auxiliary process systems

These are made up as follows:

- drain systems (gathering of hydrocarbons drained from main process systems and equipment to drain drums or to the flare Knock out drum);
- natural gas systems for use as plant fuel gas, domestic gas, derime gas (defrosting) and service gas, in the plant and for the safety of storage tanks;
- systems for cooling large equipment items;
- cool down and cold retaining systems (e.g. for maintaining LNG transfer systems at cryogenic temperatures when on standby).

9.2.4 Utility systems

The main utility systems are, depending on the type of plant:

- water, oil or heat transfer fluid for use as a heat source or for cooling as appropriate;
- nitrogen gas systems for use as service gas, laboratory gas and more specifically for:
  - safe inerting of pipes and equipment;
  - drying of pipes and equipment such as transfer arms, pump wells, etc.;
  - pressurization of small pressure vessels as an alternative means of liquid transfer;
  - seals of cryogenic rotating equipment;
  - natural gas heating value and Wobbe Index correction;
  - purging of the insulation space outside the primary container of appropriate LNG storage tanks;
- air systems:
  - instrument air;

  - pressurizing of electrical control boxes;
  - service air;
  - breathing air;
- LNG carrier supply systems:
  - liquid nitrogen;
  - bunker fuels;
  - drinking water;
  - fire water;
- steam and boiler feed water systems;
- emergency fire water from firefighting tugs to jetty connection.

Special provisions shall be taken to avoid frost damage by insulating, tracing, recirculation or burying susceptible systems.

9.2.5 Fire protection systems

The main fire protection systems are described in Clause 13, they are:

- spraying system;
- water curtains;
- water/concentrate mixture for foam generation;
- dry chemical powder.

9.3 Rules for design

9.3.1 General requirements

Recognized calculation codes for industrial piping shall be applied to the different systems described in 9.2.

Piping systems shall be in compliance with EN 13480 (all parts) piping code.

9.3.2 Flow characteristics

The piping should be designed in order to ensure a smooth flow whilst avoiding dynamic effects, e.g. surge loads, hydraulic hammers or vibrations, and adverse static electricity.

The maximum velocity for each medium shall be defined as a function of the flowing medium, its density and the potential for static electricity (see [48]).

The pressure drop calculations shall be conducted in order to check the pressure conditions required for the correct operation of the pumps on the systems for loading and unloading ships, filling of tanks (in the case of liquefaction plant) or send out from these tanks.

Pressure drops shall be calculated using validated methods (for example the Colebrook formula for the friction factor).

9.4 Pressure tests

All piping systems shall be tested according to the recognised calculation codes for industrial piping. In case of unavailable information, the following specifications are recommended:

— hydrotests: as per the PED Directives or 150 % of the design pressure if PED is not applicable;

— or pneumatic tests: as per PED Directive, or 110 % of the design pressure if PED is not applicable.

For cryogenic systems the preference is for pneumatic test. These pneumatic tests will only be carried out after approval by the local Authorities, upon demonstration that the appropriate measures are met to protect the personnel and that the stored energy is within acceptable limits (see [35]).

Safety distances may be determined by analysis of potential failure scenarios that may occur during a test.

In the absence of such an analysis, the following guidelines may be used.

Table 3 — Recommended safety distances during pneumatic tests

Pressure	Distances
bar gauge	metres
≤ 10	30
> 10 to 22	60
> 22 to 36	90
> 36 to 52	120
> 52 to 69	150
> 69 to 80	170
> 80	Not recommended

The guidelines are based on a 2" diameter and 300 mm length piping component being ejected from the system under test by the stored pneumatic energy.

In the case that the pneumatic test is not possible, a hydrotest shall be conducted and thorough drying carried out after the test; including valve disassembly if necessary. Hydrotest water quality should be adequate, especially with regard to chloride content when testing stainless steel pipe work. See 15.3.

Pipe supports shall be checked for the weight of the line full of water.

During the tests the systems and their battery limits shall be designed in order to reduce the number of "golden welds".

The flanged connections shall be checked for leakage after cleaning and in-line instrument re-installation when the system is re-pressurised. The "golden welds" should also be checked for tightness at this time.

Leakage from the system shall not be acceptable.

9.5 Piping components

9.5.1 General

The materials of construction for pipes and accessories shall be chosen according to the conditions of use. Examples of these materials are given in EN ISO 16903.

Two cases are to be considered:

— materials in permanent or occasional contact with LNG;

— materials in accidental contact with LNG due to a leakage or spillage of LNG.

In the first case, the materials shall have cryogenic properties so there is no risk of brittleness due to the temperature of the LNG.

In the second case, according to the results of the hazard assessment (see 4.4.2.3), special precautions shall be taken, for example:

— use of cryogenic materials;

— insulation with a suitable material.

In order to improve the fire resistance, the process piping system- that can be exposed to fire or heat shall not be fabricated from material with a melting point lower than steel. The fire exposed piping could exist in areas where spilled hydrocarbon could collect or accumulate and be on fire, or subject to a jet fire, following an accident or a hydrocarbon release.

For LNG or cold gas pipes, arrangements shall be made to prevent the following:

— any differential contractions sufficient to cause deformation, jamming of moving parts, alignment defects, etc.;

— icing up of components in contact with the atmosphere. If the phenomenon cannot be avoided, the weight of accumulated ice shall be considered for the calculation of supports.

Positive isolation shall be provided where it is necessary to protect personnel undertaking internal inspection or maintenance of equipment. This can be in the form of:

— a removable spool piece;

— a spectacle blind or spade and spacer.

9.5.2 Pipe

9.5.2.1 General

Piping shall be in compliance with recognized standards.

9.5.2.2 Pipe joints

Joints between pipes made by welding shall be in accordance with the following specifications:

— exclusive use of filler metals approved by the owner;

— welding according to a procedure qualified according to EN ISO 15614-1;

— use of welders and/or operators qualified according to EN ISO 9606-1;

— inspection before, during and after welding in compliance with EN ISO 9712.

Welding of different pipe materials shall be made with special care especially with regard to thermal stresses arising from differential contraction and electrochemical corrosion.

Flange joints shall be limited to a minimum in particular for maintenance operations. If these types of junctions are used, special precautions shall be taken when the bolts are tightened. More particularly, for cryogenic services, precautions shall be taken to prevent any leak during cooldown, e.g. bolt pre-tensioning, spring washers. Flanged connections shall be designed in accordance with EN 1591 (all parts).

PN designated flanges and gaskets shall be in accordance with EN 1092-1 and non-metallic flat gaskets shall be in accordance with EN 1514-1.

Non-welded joints shall be tested in accordance with EN 12308.

9.5.2.3 Pipe supports

The support shall permit the movement of the pipe due to thermal contraction or expansion without exceeding allowable stresses. The support design shall suit this function and shall prevent any cold bridge between the pipe and the structure on which it is resting or from which it is hanging.

The design of the supports and related piping shall consider the vibrations and surge loads in the line.

9.5.2.4 Compensation of contractions due to cold

All piping systems shall be subject to stress analysis using recognised piping codes. This analysis could be empirical or based on computer models, depending upon the confidence to cover all the load cases: operational (thermal, weight, internal pressure or vacuum, etc.) and accidental (surge loads, earthquake, settlement, etc.). The confidence in the results shall be documented.

Special measures shall be taken into account in order to absorb dimensional variations of pipes linked with changes of temperatures, e.g.:

— expansion loops;

— hinge type compensators capable of oscillating about its longitudinal axis (ca. 5°);

— hinged systems;

— material (e.g. Invar) that are not subject to excessive expansion/shrinkage.

It is recommended that bellows expansion joints be avoided in process lines.

Special care should be taken for small branch connections to headers to avoid any rupture or buckling of the main headers where these have thin walls, due to the application of external loads.

In case of plant expansion and new lines interconnected with the existing piping system, the pipe stress analysis shall cover the existing piping system as a minimum up to the first anchor points, on each line, where all freedom degrees are blocked. In case of vibrating lines the vibration analysis shall extend in accordance with the vibration/pulsation studies recommendations.

In case of plant debottlenecking or revamping, any change in the piping system that could affect the pipe behaviour, stability or integrity shall be subject to a new pipe stress analysis. In case of vibrating lines, any change that modifies the pipe natural frequency shall be subject to a new vibration analysis.

9.5.3 Flexible hoses

Flexible hoses may be used to make small temporary connections for the transfer of LNG and other cryogenic liquids such as refrigerant and liquid nitrogen, for example when emptying or filling road tankers of LNG or liquid nitrogen and they can also be used for transfer operations between small LNG carriers and LNG satellite plants. The use of flexible hoses shall be in accordance with the hazard assessment (see Clause 4).

Flexible hoses shall not exceed 15 m in length and 0,5 m^3 in volume. Their nominal pressure shall be limited to PN 40.

Flexible hoses shall not be used for the routine transfer of LNG between large LNG carriers and shore at conventional LNG terminals.

Flexible hoses shall be designed in accordance with relevant codes and/or standards, such as EN 12434.

9.6 Valves

Valves shall be designed, manufactured and tested in accordance with EN 12567.

— Cryogenic valves shall comply with the requirements of EN 12567. Cryogenic valves shall be capable of operating even in the presence of ice.

— In-line split body valves are not recommended in cryogenic services.

— Valves to be installed in cryogenic hydrocarbon service and toxic systems are recommended to have butt-welded ends.

— It is recommended that cryogenic welded valves be designed to enable the maintenance of the internal components without removal of the valve body from the line.

— Valves in hydrocarbon service shall be fire safe according to EN ISO 10497.

The number of valves should be limited to reduce the potential for leakage. However consideration shall be given to the following:

— requirements for sectional depressurization of pipe and equipment systems;

— safe isolation of LNG or any hazardous fluid sources or specific equipment or tankage;

— limitation of the volume of LNG or any hazardous fluid spilt in the event of a leak.

Emergency shut down (ESD) valves for equipment shall be located as close as possible to the equipment.

ESD valves should not be used as a part of process control system. ESD valves shall be fail-safe with pneumatic or hydraulic actuators. Preference is given to failsafe position spring return actuators. However, if this type is not possible, local accumulators sized for 3 single operations shall be provided. Actuators and aboveground connecting devices and cables shall be fire proofed (e.g. at 1 100 °C during the time needed to implement ESD, see 14.3).

ESD valves may be used to line up process flows. Closed ESD valves shall only be reset to an open position locally at the ESD valve

The ESD valves stroke time shall be compatible with the assumptions made during the hazard assessment (see Clause 4). The designer shall ensure that any actions, for example due to hydraulic pressure hammer (surges) on the tank or equipment nozzles caused by closing of the emergency shut down (ESD) valves shall be kept in acceptable limits.

Cryogenic extended bonnet valves shall be installed with the stem in the vertical upwards position or within 45° of vertical. Before installation in any other position, it shall be verified and tested to show in the foreseen position that the valve design does not present any risk of leakage or seizure. This requirement does not apply to small bore instrument isolating valves.

9.7 Relief valves

Relief valves should be normally installed un-insulated.

Relief valves shall be sized in accordance with the recommendations of [3] and [10] including the formulae for heat input from fires.

Thermal relief valves for the protection of equipment, piping and hoses from over-pressure resulting from ambient heat input to blocked in LNG or other light hydrocarbon liquids shall be installed. They are required where the pressure of the fluid at the maximum ambient temperature including that obtained as the result of solar radiation could exceed the design pressure, at least in the following locations:

— any volume of piping or equipment containing liquid within the section limits of the process plant;

— any volume of piping or equipment capable of isolation in particular all of sections pipe between two valves where LNG or cold gas risks being trapped in storage and (un)loading areas.

The discharge of the relief valves is dealt with as defined in 4.5.2.1.3.

When relief valves could be isolated from the equipment and/or system that they are protecting special provisions shall be implemented to ensure that the pressure in the equipment and/or system shall be continuously monitored and controlled in case of isolation valve closure. These provisions could be:

— interlocked valves in case of several relief valves;

— locked or sealed valves with safety management system;

— special working procedure under safety permit system.

9.8 Thermal insulation

9.8.1 General

The quality and type of insulation materials shall be determined in accordance with the following requirements:

— their degree of flammability and gas absorption;

— sensitivity of the insulation materials to moisture;

— large temperature gradients;

— low temperatures.

The features of the insulating materials shall be provided in accordance with the relevant codes and/or standards.

Low chloride content insulation shall be used to avoid corrosion of stainless steel.

9.8.2 Piping insulation

Piping systems shall be insulated, where required, to:

— minimize energy consumption;

— provide protection against condensation and/or frost;

— protect employees.

Insulation is provided by applying:

— an insulating material;

— a vapour barrier, for cold piping, to prevent ingress of moist air leading to condensation and freezing of water vapour;

— mechanical/weather protection, which can also ensure fire resistance where required according to 9.8.3.

When insulation is put into place, precautions shall be taken at:

— flanges, in order to provide enough space for the bolts to be satisfactorily tightened and removed;

— moving parts of piping;

— pipe supports and hangers.

Insulation on pipe joints (welds, flanges) should not to be put into place before proof test of the piping.

Consideration should be given to shop pre-insulated pipe work.

9.8.3 Fire behaviour

When designing multi component insulation systems the fire behaviour of all components, including mastic, sealants, vapour barriers and adhesives, shall be proved and documented to ensure that the system will not cause the fire to spread and any vapours emitted shall not cause an unacceptable risk of toxicity.

9.8.4 Gas absorption

For obvious safety reasons, porous insulation products likely to absorb gaseous methane shall be avoided.

9.8.5 Moisture resistance

Moisture present in insulation systems very quickly impairs the performance of the insulation materials. For example, 1 % moisture in volume contained in an insulation material reduces its thermal efficiency by 20 % to 30 %.

Water can penetrate into an insulation material in two different ways:

— either in the liquid state;

— or as water vapour which condenses within the insulation material.

Some insulation materials are waterproof to a certain extent, but most of them are permeable to gases and thus to water vapour.

In order to avoid water vapour ingress, an efficient vapour barrier shall be provided and placed around the insulation material, except when the insulation is itself water vapour tight.

9.8.6 Differential movements

A water vapour tight insulation system should be achieved. It shall be designed to remain gas tight even after undergoing the anticipated differential movements between the pipe and the various products that make up the insulation system (including the vapour barrier(s), coatings, cell fillers, metal jackets).

The joints, mostly contraction joints, shall be designed to resist differential movement cycles in relation to both internal and external temperature variations.

The thickness of each insulation layer shall, if necessary, be limited in order to reduce the shear stresses due to the temperature gradient between the warm and the cold side, to a value less than the maximum acceptable shear stress, whilst taking into account a safety factor.

9.8.7 Thickness determination

Thickness should be calculated according to EN ISO 12241 taking into account the following requirements:

- safety (sizing of the over-pressure valves);
- boil-off limitation, this limitation is determined for various reasons:
  - cost;
  - sizing of the gas treatment equipment (re condensers, disposal flares/vents);
- control of surface condensation.

When requested by EN ISO 12241, more precise methods should be used to accurately predict heat gain and insulation surface temperature, see for example [20] and [21].

The consequences of condensation are for example:

- in temperate or cold zones, outside surface condensation can turn into ice, which can lead to premature ageing of the vapour barriers or protective coatings;
- in humid regions, a large quantity of condensation can cause corrosion and has a negative influence on plant, algae and micro-organism proliferation, which in turn would accelerate ageing of the vapour barriers or external coatings.

In order to avoid outside surface condensation on the insulation system, the difference between the ambient external temperature and the surface temperature shall be limited, to ensure that the outside surface temperature is higher than the dew point temperature for about 75 % of the time when it is not raining.

This limit can be determined for each case based on local ambient conditions.

As an alternative, calculations may be based on the assumptions of Table 4 and for these conditions calculation shall be performed to show that no condensation will occur:

Table 4 — Atmospheric conditions to calculate insulation thickness if no local data are available

	Wind (m/s)	**Relative humidity** (%)	**Temperature** (°C)
Tropical zone	1,5	85	35
Subtropical zone	1,5	80	32
Desert zone	1,5	70	32
Mediterranean zone	1,5	80	30
Temperate zone	1,5	80	25
Polar zone	1,5	75	20

In case of areas where there is no natural ventilation, "no wind" conditions shall apply.

9.8.8 Thermal conductivity

The thickness depends on the thermal conductivity of the material(s) at temperatures ranging from the fluid temperature to ambient.

NOTE Manufacturer's literature and technical documents do not always give the thermal conductivity of each material at cryogenic temperatures.

As far as plastic foams are concerned, this value heavily depends on several factors such as:

- density;
- blowing (CFCs are no longer authorised);
- moisture;
- ageing.

All materials permeable to water vapour are sensitive to moisture. Consequently, the thermal conductivity correction applied on the measured values to take this into account shall be greater than in the case of temperatures close to ambient conditions, as the moisture intake is much greater.

The thermal conductivity value used for thickness calculation will need to take account of the following (see also EN ISO 10456):

- selection of insulation material:
  - water vapour tightness;
  - dimensional changes at cryogenic temperatures, especially in expansion loops;
  - deterioration;
- selection and application of the vapour barrier:
  - film or coatings;
  - single layer on the outside or multiple layers;
  - longitudinal partitioning or not;
  - quality of the products and source of supply;
  - reinforcement or not;
  - risks of deterioration and, if the equipment has been damaged, study of the risk of local or widespread damage;
  - resistance to maintenance activity;
- climatic conditions:
  - dry, temperate or tropical zones;
  - risk of outside thaw;
- risk of mechanical damage:
  - foot traffic on piping or equipment;
  - design and quality of critical points such as tees, elbows, supports, flanges, valves, etc.;

  - maintenance quality;
- qualification of the insulation contractor:
  - quality of workmanship;
  - jobsite protection in case of bad weather;
- operating temperature;
- variable or constant service temperature;
- job complexity:
  - number of elbows, connections, valves, etc.

9.9 Pipe rack/pipe way

Pipes are arranged either on a pipe-rack or pipe-way. The main and auxiliary process systems shall be routed in the open air as much as possible so as to avoid any confinement of combustible gas.

Supports shall be sized so as to resist the cases of actions defined in Annex F.

Supports shall be protected against the exposure to fire (see 13.2.1) and/or a leak of LNG or cold gas (see 13.2.2.) if required by the hazard assessment.

The ground below the pipe racks shall be suitably graded and sloped to avoid pooling of rain water and spilled hydrocarbons.

9.10 Corrosion

Piping systems shall be designed so as to prevent any leak due to corrosion or pitting during the lifetime of the plant. The choice of materials and corrosion allowances shall be made according to the operating and environmental conditions (presence of chlorides or sulphurous or nitrogenous compounds).

Special measures shall be taken such as cathodic protection and the application of corrosion-proof coatings adapted to the risk involved (see 12.3 and 16.1).

10 Reception/send out of natural gas

10.1 Metering

10.1.1 Background

Flow metering can be required for fiscal, custody transfer or material balance purposes. The accuracy of the metering systems shall be sufficient for the purpose.

10.1.2 Flow metering

Flow metering shall be conducted in accordance with EN 1776.

Turbine flow meters should be protected against bursting of the primary filter.

10.2 Gas quality

10.2.1 Background

Natural gas[5] should meet minimum requirements for gas quality when entering at the inlet of liquefaction plant.. These minimum requirements should enable to match the expected gas quality at the outlet of the liquefaction plant. The gas quality sent out to network from a receiving terminal shall meet the local requirements in particular concerning:

— total H_2S content;

— the average calorific value and the Wobbe Index range of the gas.

All domestic gas supplied can be odorized (see 10.3 and Annex M).

Gas arriving in an LNG export plant may require that certain contaminants be removed before the gas can be liquefied (refer 12.6).

10.2.2 Gas quality adjustment

Gas leaving the LNG installations shall comply with pipe gas quality parameters such as Wobbe Index, calorific value and, if required, odour intensity.

Accurate analysis of the existing streams is required to ensure that these parameters are being met. There shall be on-line monitoring and a means of correcting the gas quality parameters, should it be anticipated that it could go out of the required range.

This correction can be carried out by the addition of propane or butane to low calorific value streams (such as boil-off) or air/nitrogen to high Wobbe Index streams (such as "aged" LNG).

NOTE It can be more cost effective to produce an LNG of a quality that will not go out of the required range within the normal storage period than to adjust the gas quality at the send out.

Accurate metering, analysis and control systems are required to ensure corrective actions can be taken rapidly and smoothly.

10.3 Odourizing

Odourization storage and injection equipment may be provided at installations where required either by local regulation or at the client's request for gas entering the supply system.

Specifications for the characteristics of odourants, construction and operation of odourization installations shall be in accordance with relevant standards. If no standard exists, odourization installations may be designed in accordance with Annex M.

11 Boil off recovery and treatment plants

11.1 General

Boil off recovery plants shall be installed in order to collect LNG boil off due to heat in leak and flash present in the feed when filling tanks or when loading LNG carriers.

The vapours shall be safely disposed of through re-liquefaction, used as fuel gas, vapour to tankers (terminals only), re-compressed to gas network or as a last resort flared or released to the atmosphere.

Precautions shall be taken to prevent any penetration of air into the boil off recovery systems.

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[5] If feed gas is synthetic or biogas, the same rules shall apply.

The boil off recovery plants generally comprise:

— boil off collection pipe-work;

— system(s) of gas transfer to/ from the tanker(s);

— boil off gas compressors;

— re-condensers and or re-liquefaction system.

11.2 Boil off collection system

This system shall be designed so that no direct emission of cold gas into the atmosphere can arise during normal operation.

The system shall be designed at least for the following:

— boil off of tanks and all receivers containing LNG;

— degassing systems of piping and equipment containing LNG;

— gas displaced from a LNG carrier during loading.

The boil off system shall be designed applying the same sizing rules as those defined in Clause 9. The constituent materials shall have cryogenic properties (the boil off gases can reach temperatures close to - 160 °C). The lagging of pipes shall be of the same thickness as that of low pressure LNG pipes of the same diameter, unless the boil off is routed to the flare/vent system (see 11.6).

The maximum working pressure of the boil off system shall be compatible with the maximum pressure capable of arising at the time of the opening of the degassing system or be equipped with a double pressure limiting device.

Valved drain points, connected to the drain system shall be installed at low points of all main lines or flare lines (upstream of flare knock out drum).

The connections between the tanks and boil off collection system are recommended with valving and instrumentation enabling:

— isolation of a tank;

— reduction of the pressure of one tank, without altering the pressure of the others;

— the measurement of any boil off rate reduction each tank, as part of the strategy for roll-over prevention as described in 6.9.1.

11.3 System of gas return to tanker(s) or to export terminal

The system connects the boil off collection system to the vapour return arm of the jetty.

It shall provide for the transfer of gas from the tanks to the LNG carrier or reverse, in order to compensate the volume of liquid displaced during unloading or loading, and the collection of boil off from the tanker while it stays at the jetty.

If necessary, a blower or booster compressor can be used.

The pipes shall have the same characteristics as those of the collection systems.

11.4 Boil off gas recovery

The boil off gas can be:

— re-liquefied;

— re-condensed in the LNG send out prior to vaporization;

— used as fuel gas;

— re-compressed and sent to gas network.

In receiving terminals, the boil off gas is usually compressed and cooled, then introduced into a re-condenser where it is re-liquefied in contact with all or part of the send out flow of low pressure LNG.

The re-condenser shall be designed in accordance with EN 13445 (all parts) and shall be made up of materials with cryogenic characteristics. It shall be insulated.

11.5 Gas compressor

The compressors shall be equipped with systems to limit the pressure downstream to avoid the risk of exceeding the maximum design pressure of the equipment that is installed downstream.

Gas compressors shall be equipped with a shut down sequence either manually or automatically initiated which enables them to be isolated in the event of serious damage.

Adequate ventilation shall be provided in any space of a gas compressor, such as the crankcase, that could become over-pressurised. Vents shall be led to a safe area.

11.6 Flare/vent

11.6.1 General

All emissions to the atmosphere shall be monitored, controlled and registered.

The facilities shall be fitted with a flare or vent system(s).

The flare or vent has two conditions: the normal and accidental flows.

The normal flow rate results from all operating configuration modes, either steady or transient, nominal or downgraded, but staying within the facility initial design intent.

The accidental flow rate is the highest flow rate that results from an uncontrolled and/or unplanned event which may occur during operation. It is the sum of the normal flow rate and the highest total flow related to other possible uncontrolled /unplanned scenarios that may occur simultaneously.

The hazard assessment shall determine the combination(s) of events which may actually occur simultaneously without double jeopardy (simultaneous unrelated events).

If for any reason, some downgraded situations are not included in the "normal flow rate" (e.g. commissioning, cooling down of warm LNG tanker from dry docking, etc.) the designer shall check that the related flow rate added to the normal flow rate is lower than the accidental flow rate.

The conditions that cause these flows vary significantly between LNG import and export terminals.

The layout of the flare/vent shall respect the radiation flux levels defined in Table A.3 and where practicable shall be chosen according to the prevailing wind in order to minimize the risk of the flame being reached by a flammable gas cloud (flare) and flammable gas cloud reaching an ignition source (vent).

11.6.2 For import terminal

The facility is designed around the premise of no continuous flaring or venting, 4.2.4. Under accidental conditions a flare or vent shall safely dispose of all envisaged flows. The two indicative flow-rates, normal and accidental, are identified and defined as:

- the normal flow rate which is the sum of the flow rates defined in 6.7.2, excluding roll-over, and the boil off gas due to heat input of all receivers containing LNG (pipes, drain drums, etc.). This flow rate is intermittent by definition;
- the accidental flow rate, which is the greater of the two following combinations:
  - normal flow rate and flow rate at the outlet of the safety relief valve of one vaporiser as defined in 8.1.6, if it is connected to the same flare/vent system;
  - normal flow rate and flow rate at the outlet of the relief valves of one tank as defined in 6.7.3, if they are connected to the same flare/vent system.

The flare/vent shall be sized for the maximum gas flow rate that can be envisaged, i.e. accidental flow rate. If the relief valves of tanks and vaporisers are not connected to the flare/vent system, alternative flow conditions will form the basis of the accidental flow rate. This typically can include one or a combination of the following:

- normal flow rate, 6.7.2, excluding roll-over;
- emergency loads such as depressurizing loads;
- one or more abnormal operating loads such as:
  - unloading of an LNG carrier without returning gas displaced from the storage tank to the carrier for some reason;
  - cool down of the LNG carrier tanks;
  - off-spec gas that cannot be recovered and has to be flared/vented.

High-pressure gas release may be routed to a separate flare/vent, for example the flow rate from the relief valve of one vaporiser which for the situation is considered to be the accidental flow rate.

11.6.3 For export terminal

The events creating the accidental loads on the flare/vent shall be tabulated in a relief and de-pressurizing summary to establish the accidental flare/vent load.

Relief loads arising from control valve failures and blocked flow outlets are often defining the accidental load cases.

Normal loads arise from any event that is under the control of the operator plus loads due to heat leakages and loading operation.

Often a separate low pressure flare is provided for the storage and loading area.

Export terminal often have "wet" and "dry" flare systems.

Wet system carries gas with significant water content.

Dry flare systems are for cryogenic quality gas.

Acid gas flare systems are sometimes provided.

12 Auxiliary circuits and buildings

12.1 Electrical equipment

12.1.1 General requirements

All electrical equipment, instrumentation equipment and installations located in hazardous area (see 4.5.2.1.2) shall be in accordance with the EN 60079/ IEC 60079 series according to Clause 2.

A study should be undertaken to define the required IP classification for electrical equipment as specified in EN 60529 and EN 60034-5.

12.1.2 Main electric power supply

The plant may either import electrical power from the local grid or generate its own power, or a combination of the two cases.

If power is imported from the local grid, it is preferred that there are two independent incoming power lines to maintain supply integrity. The power supply to the plant system should be reviewed to identify any point where the independent lines may join or where there is a risk to both independent supplies from a common mode failure.

The incoming lines shall each be rated to:

a) carry the full load of the LNG plant;

b) enable at any time the starting of the largest motor on the plant without excessive voltage drops at the main bus-bars or the other motor terminals.

Grid transmission voltage is stepped down to site voltage at the entry to the plant by power transformers. The transformers should each be capable of supplying the full load of the plant.

Where the plant generates its own power without connection to a grid, the power source shall have spare capacity to allow one power generating unit to be off line and still maintain the necessary power to the plant.

Where the plant generates its own power there shall be provision to start the plant up from complete shutdown. This is often called a "black start". Start up procedures shall consider that the normal fuel to the power generation units may be unavailable at a black start.

The owner should consider if a stability analysis of the electrical system is required, particularly if variable speed drives are used. The effect of a short duration voltage dip should be considered.

12.1.3 Emergency Power Supply (EPS)

An Emergency Power Supply shall be provided. It shall be designed to ensure, in case of failure of the main electrical power supply, all the vital functions for the safety of staff and the facility are maintained.

The capacity of the emergency electrical power shall be adequate to bring the plant to a controlled and orderly shutdown state in the event of total loss of power supply. The designer shall identify all loads on the emergency generator.

In case of plant expansion, the EPS capacity shall be checked to ensure that the minimum loads are still covered.

As a minimum it shall:

— provide power for one in-tank pump;

— ensure the LNG carrier can cease a transfer operation and leave the berth if required;

— maintain all safety critical; loads (process instrumentation, fire and safety equipment and associated systems, MOV's (Mechanically Operated Valves), telecoms, warning lights, essential lighting, etc.);

— start and run the firewater jockey pumps;

— maintain sufficient power to the electric circular ring of the heating (if fitted) of the LNG storage tanks foundations, in case of above ground tank or to the needed electrical heating systems in case of inground tank;

— provide an instrument air and/or nitrogen supply if required for safety functions.

Emergency generator shall have a minimum of 24 h fuel supply in the "day tank" sited at the generator and be capable of being refuelled when running.

The designer should establish if main equipment items need a power supply to ensure safe shut and cool down.

12.1.4 Uninterruptible Power Supply (UPS)

An Uninterruptible Power Supply shall be provided.

It shall provide power to critical control and safety systems so that the plant may be kept in a safe condition for a minimum of 60 min.

In case of plant expansion, the UPS capacity shall be checked to ensure that the minimum autonomy is still maintained.

12.1.5 Lighting

Lighting shall be provided in plant areas where safe access and safe conditions for work activities is required at night.

An emergency battery lighting system shall be provided to allow the safe escape of staff from accessible areas of the plant in the event of a power and essential lighting failure, or an emergency situation.

12.2 Lightning and earthing

12.2.1 Lightning protection

Lightning protection shall be in accordance with EN 62305 (all parts).

The following installations shall be, as a minimum, protected against lightning:

— tanks and their accessories;

— marine transfer arms;

— buildings;

— flares and vents.

12.2.2 Earthing circuit

Earthing shall be in accordance with CENELEC standards, in particular HD 60364-5-54.

The design shall ensure personnel protection and avoid potential difference between metallic components and the possibility of spark generation in hazardous areas.

12.3 Cathodic protection

All underground/subsea metallic parts should be protected where necessary against corrosion using appropriate coating and/or cathodic protection in accordance with the relevant codes and/or standards.

In case of plant expansion, the anode beds shall be checked to ensure that the minimum loads are still covered.

12.4 Warning lights

Tanks and other elevated structures shall be fitted with warning lights to comply with air and safety navigation regulations.

The jetty shall have navigational lights in accordance with local marine regulations.

12.5 Sea water supply

12.5.1 Materials

Materials shall be carefully selected in terms of fluids and the site environment.

Particular attention shall be paid to the compatibility of materials to avoid any galvanic corrosion.

12.5.2 Water pumping

It is recommended that the number and sizing of cooling water pumps or seawater pumps is such that unavailability of a pump of the highest rated capacity will not prevent the water requirements of exchangers and cooling services from being met.

The design of the seawater intake often requires detailed study to ensure that the filtration and hydraulic requirements of the seawater pumps are correctly addressed.

Filtration shall be provided in accordance with pump and related equipment manufacturer requirements.

Water circuits are susceptible to internal corrosion and/or fouling by natural organisms. Measures to prevent this should be fitted if required. The discharge of water treated with anti- corrosion and anti-fouling chemicals shall be in compliance with the discharge permit(s) for the plant (see 4.2.1, 4.2.2 and 4.2.3). The discharge temperature of the water shall be in compliance with the discharge permit(s).

12.6 Gas contaminant removal plant

Some liquefaction plants require gas treatment to remove gas contaminants such as mercury, sulphur, carbon dioxide, mercaptans and aromatics from the incoming gas.

Facilities and procedures shall be in place for the secure handling, storage and recycling or disposal of these materials and their removal media if required.

Material Safety Data Sheets for the absorption and reactant media shall be provided and shall state specific requirements for safe disposal or recycling of the material in a "used" or "spent" condition.

12.7 Instrument air

When instrument air is used its supply shall be reliable. This shall usually mean the provision of at least two air compressors each capable of supplying the total requirement.

Instrument air supplies shall be guaranteed for the time interval needed to put the plant in a safe condition on failure of the main power source. This shall be for a minimum of 3 min. This may be achieved by for example, providing air receivers to provide the necessary storage.

If the instrument air compressors are electrically driven, at least one, capable of supplying the total requirements, should have its power supplied from the emergency power supply.

The air shall be dried to a dew point compatible with the plant minimum ambient temperature conditions. The dew point shall be at least −30 °C and 5 °C below ambient temperature (both referenced to atmospheric pressure).

The instrument air system is to be independent of the plant air or service air systems.

12.8 Fuel (utility) gas

An LNG plant may be equipped with a fuel gas system. The main applications depending on the type of the plant are the following:

— gas fired vaporizers;

— gas turbine or gas engine driven compressors and generators;

— steam boilers and process heaters;

— tank safety, as vacuum breaker gas;

— flare pilot gas and purge.

Fuel gas used within the plant shall not be odorized. Leak detection shall be provided by the gas detection system as 13.4.

12.9 Nitrogen system

Nitrogen can be produced on site or delivered as liquid nitrogen by road or rail.

Certain process conditions such as molecular sieve regeneration or for injection as a component in a make-up stream may require that a high quality nitrogen supply is used.

The nitrogen is used mainly for:

— gas treatment (calorific value adjustment);

— pressurization;

— equipment, LNG tank insulation space and piping purging;

— drying and inerting;

— rapid extinction of flares and vents;

— cooling;

— refrigerant cycle make up.

The liquefied nitrogen pipe-work shall be designed with cryogenic materials in accordance with recognized local codes and/or standards, examples of acceptable materials are given in EN ISO 16903.

Cross connection between gaseous nitrogen systems and air systems is not permitted for safety reasons.

12.10 Buildings

Building design and construction shall comply with the requirements of hazard assessment (see 4.4.2.5), the following standards and with local regulations, especially for seismic design:

— EN 1992-1-1;

— EN 1993-1-1;

— EN 1994-1-1;

— EN 1998-1.

For the electrical installations of buildings, see also [11].

Where identified in the hazard assessment, buildings shall be pressurized (see EN 60079-13 guidelines). Forced ventilation air intakes for buildings shall be fitted with gas detectors to shut down ventilator fans and inhibit start up to avoid any risk of sending gas into the building.

The permanently manned control rooms shall be designed to enable occupation for sufficient time for the emergency procedures to be put into effect and to permit evacuation to a safe location. The heating, ventilation and air conditioning system shall be designed to suit the possible received radiation flux (see 4.4.2.5 and Annex A).

Where buildings are designed for blast over-pressure the design shall consider the risk to personnel caused by the blast wave entering the building through ventilation inlets and outlets.

13 Hazard management

13.1 Inherent safety

13.1.1 Provision for minimum safety spacing

The safety spacing shall be calculated considering possible fire radiation levels and gas dispersion zones. The allowable exposure levels are specified in Annex A. Safety distances between LNG tanks, process units, control rooms etc. shall comply with the minimum requirements to achieve these threshold values.

13.1.2 LNG Plant layout

The siting of an LNG plant with respect to the surroundings shall be covered by a site location assessment, see 4.3.2.5.

The following clause concerning the plant layout uses the terms “hazardous areas” and “hazard affected areas”. In this context the hazard affected areas are those areas where those events described in 4.4 could arise. The term hazardous area applies specifically to those areas that are defined in 4.5.2.1 b).

The LNG plant shall be laid out to provide safe access for construction, operation, maintenance, emergency action and comply with the layout requirements identified in the Hazard Assessment according to 4.4.2.

Separation distances shall take into account, in particular:

— radiation flux levels;

— lower flammability limit contours;

— noise;

— blast effects.

The prevailing wind direction shall be considered in LNG plant layout. Where practicable, buildings and ignition sources should not be downwind of possible accidental and planned releases of flammable materials. They shall be located outside hazardous areas.

Plant buildings should be sited outside the hazard affected areas or designed to resist these accident scenarios. The building's level of occupancy shall also be part of this evaluation.

The central control room shall be located outside process areas and should be outside hazardous areas. Furthermore, it shall be designed to operate during and resist those accident scenarios that have been identified in the Hazard Assessment.

For all equipment, such as air compressors, fired process equipment, gas turbines, diesel driven fire water pumps and emergency generators, the air intake shall be located outside zone 0 and 1 areas. Air intakes shall be fitted with gas detection which will trip the equipment.

The spacing between two adjacent tanks shall be the result of a detailed hazard assessment. This shall be a minimum of half the diameter of the secondary container of the larger tank.

Additional guidance on plant layout is given in the following reference [8], [9] and [49].

13.1.3 Escape routes

Escape routes shall be provided for all plant areas where a hazard to personnel may arise. Escape routes shall be laid out to encourage an intuitive response from personnel to lead them from high hazard areas to low hazard areas and shall consider that there may be some panic in an emergency situation. The design shall take into account the fact that when LNG is spilled a "fog" is created by condensation of atmospheric humidity.

13.1.4 Confinement

Confined or partially confined zones shall be avoided as far as possible, in particular:

— gas and LNG pipe-work shall not be situated in enclosed culverts when it is possible to avoid this for example where road bridges cross pipe ways;

— the space situated under the base slab of raised tanks, if any, shall be sufficiently high to allow air to circulate;

— where cable culverts are used they shall be filled with compacted sand and covered with flat slabs featuring ventilation holes to minimize the possibility of flammable gases travelling along the culverts through voids above the sand. As the sand settles the slabs will sink. They can be restored to their original elevation by adding sand.

13.1.5 Direct accessibility to valves and equipment

This is achieved by providing in the plant all the required safe accesses, paths, staircases (/ladders) and platforms, as required by the layout review(s) 4.5.3.

The road system should be developed to provide a direct access for the firefighting trucks and other emergency response vehicles.

13.1.6 Selection of appropriate electrical components according to the classified area

Electrical equipment to be installed in hazardous areas will be qualified in accordance with EN 60079 / IEC 60079 series according to Clause 2.

Availability of required certificates shall be carefully checked on an individual basis.

13.1.7 Spillage collection, including paving in hazardous area

Restricting the extent of a potential LNG or hydrocarbon leak is achieved by:

— limiting the volume of the possible accidental spills;

— containing these spills within defined impounding and spill collection areas, to prevent their spreading to other areas of the plant or outside the plant boundary and minimizing the vapour cloud dispersion distance;

— making provision to properly remove rainwater whilst LNG or hydrocarbon spill will be contained in the collecting systems and will not ingress into drains or other water courses;

— controlling leaks and spillage.

Where dispersion calculations show that a leak can escalate to a more serious incident fixed leak detection systems with advisory or executive action to stop the leak source, are required to isolate sections of plant and to shutdown sources of ignition.

The design of impounding basins shall be such that flammable fluids cannot enter the surface water drainage system. Spill detection devices and means to control the evaporation rate (e.g. foam generation see 13.6.5) should be provided. These channels and the impounding basin may be lined with an insulating layer to limit evaporation (see EN 12066).

Separation systems relying on the differential densities of water and LNG are not acceptable.

13.1.8 Retention systems in process and transfer areas

Liquid spills within process and transfer areas shall be confined within a spill collection area and shall be drained to an impounding basin.

Subject to the results of risk analysis, the impounding basin may be located in the vicinity of, or remote from, the spill collection area. The spill collection area and the impounding basin shall be connected by open channel.

For process areas, the spill collection system or impounding basin capacity shall be at least 110 % of the largest expected spill according to the risk analysis performed. Flash may be considered for capacity calculation. In case of plant expansion or plant debottlenecking, the spill collection system and impounding basin capacity shall be checked to suit the new inventories.

At transfer areas and in the interconnecting pipe-work, where there is a potential for leaks (valves, equipment or instruments), the impounding basin capacity shall be determined by risk analysis considering potential leak sources, flow rates, detection systems, manning levels and response times.

13.2 Passive protection

13.2.1 Fire proofing

Fire proofing shall be used to protect equipment, typically: ESD valves, safety critical control equipment, vessels containing quantities of liquid hydrocarbon and structural supports, which on failure would escalation the incident and/or endanger the activities of emergency response personnel. Equipment which can receive thermal radiation, in excess of that defined in Annex A, for a sufficient period to cause failure shall be provided with fire proofing protection. The fire proofing shall provide protection for the duration of the hazard event but shall as a minimum provide 90 min protection.

Fire protection in the form of insulation or water deluge shall be provided for pressure vessels, which can receive thermal radiation fluxes in excess of that defined in Annex A, to prevent such vessels failing and releasing superheated liquid, which can result in a BLEVE, (see EN ISO 16903).

It shall be recognized that pressure vessels subject to radiation from a major incident such as an LNG tank fire shall require protection for much more than 90 min. Protection for long duration incidents may not be achieved by insulation and a water deluge system is required.

The calculation of water deluge, insulation for fire protection of structures, etc. as protection against fires shall be performed for the fluid which gives rise to the highest radiation flux.

Fire proofing can be provided by:

— preformed or sprayed concrete;

— insulation materials made of mineral fibre, ceramic, calcium silicate or cellular glass;

— intumescent coatings.

Fire proofing shall be designed and executed in accordance with the appropriate standards (see [7] and [31]).

13.2.2 Embrittlement protection

The effect of low temperature fluid spills on adjacent plant, equipment and structural steel shall be assessed and measures taken to prevent incident escalation and/or endangerment of emergency response personnel, through suitable selection of materials of construction or by embrittlement protection.

Such protection shall be achieved by an appropriate material selection (concrete, stainless steel, etc.) or by a insulating with material that will protect the equipment and structural supports from cold shock. Insulation shall be designed and installed in accordance with appropriate standards and provision taken to protect outer surfaces from wear and tear.

Equipment and structural support elements should be protected in such a way that their function and form are not adversely affected during the plant operation.

13.3 Security

The security should be covered by:

— Anti-intrusion

  The anti-intrusion system should be installed along the fences to monitor undesired ingress in the plant.

— Access control

  An access control system shall be installed in order to control the access to the various areas of the plant.

  It may include badge readers, intercom, door contacts and anti-intrusion sensors.

  The access control system will consider the different access levels (control rooms, process areas, general facilities, etc).

The security control system should be linked to the CCTV to allow remote monitoring.

13.4 Incident detection and signalling

Systems shall be provided to detect possible accidental events, which could occur in the plant.

The arrangement of detectors shall be such as to always provide redundancy and to prevent false and spurious alarms. Voting technique arrangement may be used.

Events may include:

— Earthquake

  Where applicable seismic acceleration monitoring shall be provided, giving signals to automatically initiate the plant shutdown when the earthquake reaches a pre-defined level. This pre-defined level is chosen by the operator.

— LNG spillage, gas leakage, flame and smoke

  These detection systems are intended to rapidly and reliably detect any LNG spillage or flammable gas leakage and any fire condition in the plant.

  Continuously operating detection systems shall be installed at every location, outdoors and indoors, where leaks are credible.

  The following detection devices may be provided:

  — LNG spillage detection;

  — LNG spills should be detected by low temperature sensors, for example, resistance type device's or fibre optic systems. The sensors shall be, protected against accidental damage;

  — Flammable gas detection.

    The flammable gas detectors may be of the infra-red type, or of equivalent performance.

    Along critical fences, open path type gas detectors may be installed.

    For location of gas detectors, see [27].

  — Flame detection

    Flame detectors should be proven in the detection of the type and size of fire predicted flame detectors may be of the ultraviolet/infrared (UV/IR) type, or equivalent performance.

  — Heat detection

    High temperature detectors should be provided for protection of tank relief valves fires and activation of tailpipe extinguishing package(s) if provided.

    The heat detectors may be of the high temperature thermistor strip type, of the temperature-sensitive pneumatic type, or equivalent performance.

  — Smoke detection

    Smoke detectors may be of the double ionization chamber type, or equivalent performance.

— Manual call points

Manual call points shall be provided in the hazardous plant areas, typically those plant areas covered by flame and/or combustible gas detectors, and provided on likely escape routes from these areas.

— CCTV (Closed Circuit Television Camera) monitoring

Remote operated cameras should be installed for viewing all events which could occur in hazardous and unmanned areas.

Under abnormal circumstances the operator should have the ability to use these CCTV systems to analyse the situation.

The system shall be considered as a priority load and is connected to the UPS system. The system should automatically respond to alarms, and focus information presented on VDU's in the appropriate control room(s).

— Communication system

The control room operators shall be able to communicate with field operators via the terminal communication systems (specific mobile phones and radios).

Special consideration should be given to buildings with high noise levels where visual alarms should also be installed.

A combination of visual and sound alarms shall be installed in all plant locations.

Direct communication links should be available with the Port Authorities, the LNG carrier and the pipeline dispatching centre.

13.5 Emergency Shutdown System

The ESD system, which is fully described in the Clause 14, includes:

— a Safety Control System (SCS);

— a Fire, Spill and Gas Detection System (FSGDS).

The alarms initiated by the Fire, Spill and Gas Detection System (FSGDS) are reported by and perform the required automatic actions via the Safety Control System (SCS).

The SCS interface system gives the operator detailed information on areas involved in the hazardous event, type of hazard, concentration of gas, where in the area (if applicable), detector or loop involved, status of fire water pumps, status of protection systems, status of HVAC equipment involved (fans, dampers, etc.), wind force and direction, temperature and relative humidity, system faults, reduced safety in the fire zones.

The alarms received in the control rooms, details of automatic actions taken by the SCS together with detailed incident information and CCTV coverage, aid the operators in selecting appropriate operator controlled actions, such as:

— shut down or isolation of the process system involved;

— activation of appropriate remote operated fire protection systems;

— initiate emergency actions by operators with mobile/portable firefighting material.

13.6 Active protection

13.6.1 Active protection definition

The active protection should include:

— fire water mains network, with hydrants and monitors;

— spraying systems;

— water curtains;

— foam generators;

— fixed dry chemical powder systems;

— firefighting vehicle(s);

— portable/mobile fire extinguishers.

13.6.2 Fire water system

Water is employed in many firefighting systems, and has particular uses on an LNG plant. However, LNG pool fires are neither controlled nor extinguished by water. Application of water on a liquid surface will increase the vapour formation rate thus increasing the burning rate with negative consequences on fire control. On an LNG plant, under fire conditions, water may be used in great quantities for cooling storage tanks, equipment and structures which are subject to flame impingement or heat radiation due to a fire. As a result, the risk of escalation of the fire and deterioration of equipment can be reduced by early and concentrated cooling.

Plant surface water and fire water drainage systems and LNG spill collection systems shall be designed to minimize the possibility of fire water increasing the vaporization rate of any LNG spill. This may be achieved by plant area and fire water systems segregation. In the event that firewater run-off is contaminated provision shall be made to prevent the pollution of natural water-courses.

As a minimum, two fire water pumps shall be installed. Independent power sources shall be provided in such a way that full capacity can be delivered, taking into consideration the unavailability of one pump.

Fire water networks should be provided around all sections of the plant. Water supply systems shall be designed in independent sections so that in case of maintenance or damage of a section the water supply to other sections is not interrupted. Both fire pumps should not discharge to the network through a single header.

All these networks, including fire hydrants shall be maintained primed under a minimum pressure at all points for example by means of jockey pumps or an elevated tank.

Special provisions shall be taken to avoid any damage due to freezing; such as tracing.

Water supply systems shall be able to provide, at firefighting system operating pressure, a water flow not less than that required by the firefighting systems involved in the maximum single incident identified in the Hazard Assessment in 4.4 plus an allowance of 100 l/s for hand hoses. The fire water supply shall be sufficient to address this incident, but shall not be less than 2 h.

LNG plants (particularly impounding basins) shall be equipped with drainage systems capable of draining the volumes of water generated by these systems.

13.6.3 Spraying system

The importance of cooling each equipment item and the amount of water required will depend on the hazard assessment (see 4.4).

Where required, spraying systems shall distribute the water flow evenly onto the exposed surfaces. In this way equipment subjected to radiation shall not reach unacceptably high local temperatures.

Recirculation of used water may be considered where practicable and shall depend on its ability to remove the transferred heat in a fire of long duration while keeping the integrity and working ability of the unit. Precautions should also be taken to ensure that flammable materials are not returned with the re-circulated water.

The calculation of the incident water flow on each unit shall be carried out on basis of received radiation flux for each scenario defined in 4.4 using appropriate validated models in order to limit the surface temperature consistent with the integrity of the structure.

13.6.4 Water curtains

13.6.4.1 General

Water curtains may be used to mitigate gas releases and protect against radiant heat.

The aim of a water curtain system is to rapidly lower the gas concentration of an LNG vapour cloud in order to attain the lower flammability limit of gas in air.

Water curtains transfer heat to the cold natural gas cloud through contact between LNG vapours and water droplets.

In addition water curtains entrain large volumes of air that transfer additional heat, dilute the LNG vapour cloud, thus enhance its buoyancy thus facilitating its dispersion.

The effectiveness of a water curtain is reduced as the wind speed increases, but natural dispersion is increased at high wind velocities.

Effective performance of water curtains is dependent on many different conditions, i.e. nozzle type, water pressure, nozzle location, nozzle spacing.

Water curtains are known to mitigate heat radiation and gas cloud dispersion incidents. However they cannot be relied upon as the primary means of protection.

Water curtains could be installed at impounding basins to assist vapour dispersion. The design at the impounding basin should minimize the potential for water from the water curtains draining into the impounding basin.

13.6.4.2 Characteristics and location

It is recommended that water curtains are positioned as required by the hazard assessment, 4.4.

Water curtains can be located as close as possible to the area of possible spill and concentration of LNG taking into account plant requirements. The possibility of water curtain droplets entering the impounding areas should be minimized in order to avoid an increase in the LNG evaporation rate.

Water curtains may be positioned around the impounding areas. In this way they act as a barrier for cold natural gas clouds originating from LNG leaks.

Nozzle spacing should follow vendors' recommendations.

13.6.4.3 Supply system and volume of flow

The recommended volume flow rate of water is 70 l/min/m run.

13.6.5 Foam generation

Firefighting foams can be used to reduce the heat radiation from LNG pool fires and aid safer gas dispersion in the event that the leak does not ignite. The extent of their use will depend on the hazard assessment, see 4.4.

Foam generators shall be specifically designed to operate when engulfed in an LNG fire, unless the design of the system is such that the generator is protected from excessive heat flux. The design of the system shall prevent water in a liquid form from entering the impounding area.

Foam to be used shall be dry powder compatible and proven suitable with LNG fires in accordance with EN 12065. Typical expansion ratios should be in the order of 500:1.

LNG impounding basins or areas should be fitted with fixed foam generators to enable rapid response and remote activation.

The volume of foam flow for LNG impounding basins or areas shall be determined in accordance with EN 12065 in order to reduce heat radiation, taking into account the possible failure of one generator and also the destruction rate of the foam due to fire. A foam retention device may be placed around the impounding basin or area where there is a risk of foam loss due to wind.

Foam agent reserves shall be situated in a place sheltered from heat radiation (from fire and solar).

The foam agent storage capacity (Q) shall be at least equal to the sum of the following quantities:

$$Q = Q_1 + Q_2 + Q_3$$

where

$$Q_1 = t \times r \times S$$

t is the foam agent procurement time (hours), (with a ceiling at 48 h);

r is the foam agent destruction rate (metres/hour) (for example r = 0,11 m/h);

S is the largest area to be covered (square meters);

Q_2 is the quantity necessary for periodic foam system tests. In the absence of other information, operation of the foam agent pumps at the maximum flow rate for 15 min is to be taken for determining this quantity;

Q_3 is the quantity necessary for first layer build-up.

13.6.6 Portable foam equipment

The requirement for portable foam equipment shall be defined by the Hazard Assessment, 4.4. When provided, portable foam – generating equipment connected to the firewater supply shall be equipped with enough hose to reach the most distant hazard they are expected to protect.

13.6.7 LNG fire extinguishing with dry powder

13.6.7.1 General

Equipment for LNG firefighting shall be in accordance with relevant codes and/or standards.

The recommended extinguishing medium for LNG fires is dry powder.

To extinguish a burning pool of LNG, dry powder shall be applied above the surface of the liquid without allowing the powder to impinge and agitate the surface.

Agitation of the liquid surface will increase the burning rate due to the increase in vapour formation instead of extinguishing the fire.

To achieve optimum results in extinguishing an LNG fire, the fire's total area shall be covered immediately and all at once. Otherwise, residual flames of LNG pool sectors can rapidly re-ignite gas emanating from the extinguished sectors. In addition, provisions shall be taken to cool any structure surfaces which could re-ignite the gas.

It is recommended to have enough quantity of powder to allow a second shot in case of a re-ignition.

13.6.7.2 Types of dry powder

The dry powder shall be proven suitable for gas fire extinguishing; foam compatibility shall be in accordance with EN 12065.

Dry powder may be of one of the following types:

— based on sodium bicarbonate;

— based on potassium bicarbonate.

13.6.7.3 Location of dry powder systems

Dry powder systems should be installed in an LNG plant near points of possible LNG and hydrocarbon leakage with regard to the hazard assessment and typically near the following units:

— loading/unloading areas (as specified in EN ISO 28460);

— LNG pumps;

— ESD valves;

— tail pipes of tank PSV (fixed systems).

13.6.8 Portable/mobile fire extinguishers

The following types of extinguishers are foreseen:

— foam type extinguishers in area where oil may be present (compressors building, hydraulic unit of transfer arms at the jetty);

— carbon dioxide type extinguishers in electrical and instrumentation buildings;

— dry chemical powder extinguishers in process areas.

The fire extinguishers shall comply with the requirements of the local regulations.

These extinguishers are installed in the critical locations along the circulation paths and/or platforms. Their position shall be on a recognized escape path from the identified hazard they are installed to mitigate.

13.6.9 Firefighting vehicle

Where external LNG experienced assistance in case of emergency is not available the plant shall be equipped with at least one firefighting vehicle to give the required response in case of emergency.

This firefighting vehicle will be fitted with:

— foam system suitable for the anticipated type of fire;

— dry chemical powder, A-B-C type as a minimum.

Fireman protective clothing suitable for LNG service (splash and fire) shall be provided.

The vehicle shall be sufficiently equipped and manned to provide emergency response whilst waiting for off-site support.

13.7 Other requirements

13.7.1 Provision to minimize hazards in buildings

This is achieved by maintaining a continuous positive pressure ventilation in the electrical and instrumentation rooms of the buildings located inside the process areas.

In case of gas detection in the process areas, the operators in the control rooms have the possibility to shutdown remotely the HVAC of the affected buildings.

In case of gas detection at the building air inlet, the external fans are tripped and the louvers closed in order to prevent any gas entrance in the electrical and instrumentation rooms where a risk of ignition exists.

13.7.2 Fire cabinets / hoses boxes

An accessible supply of firefighting equipment shall be located where hydrants are intended for use by either plant personnel or the local fire brigade.

Equipment shall be stored in cabinets which are:

— clearly identifiable;

— provided with means to securely store equipment;

— suitably constructed and protected for the plant local environment;

— naturally ventilated;

— located so that personnel can gain access from a safe area.

Where provide cabinets and their required contents should be approved by the local fire authority. As a minimum each cabinet should be equipped with:

— two adjustable mist/solid stream nozzles:

— one hydrant spanner;

— four coupling spanners;

— two hose coupling gaskets;

— four x 15 m lengths of fire hose;

— a weatherproof list of contents.

13.7.3 Terminal firefighting maintenance and training

Fires occur only rarely on terminals but can have severe consequences when they happen.

Accordingly, and with respect to emergency situations, the interest of operation personnel shall be kept high by suitable drills including the use of equipment.

Proper maintenance of the firefighting equipment is of primary importance. Inspection and maintenance shall be incorporated into the terminal management programmes to ensure that personnel are familiar with the firefighting equipment, its location and use under emergency conditions.

14 Control and monitoring systems

14.1 General description

The LNG plant control and monitoring systems shall enable as a minimum the operator to:

— monitor and control gas processing and essential auxiliary systems;

— be rapidly and accurately informed about any incident that may lead to a hazardous situation;

— monitor and control plant safety;

— monitor and control of site access and egress;

— exchange information internally and externally under both normal and emergency conditions.

Generally, these main plant functions will be performed by:

— the process control system;

— the safety control system;

— the access control system and the anti-intrusion system;

— the internal and external communication networks.

The safety control system shall be independent from the other systems.

14.2 Process control system

14.2.1 Principle

The process control system shall provide the operator with real time information to allow safe and efficient operation of the plant.

Some equipment can have an individual process shut down (PSD).

Common process parameters can lead to a PSD of groups of equipment; this PSD may be activated by either process control system or the safety control system.

14.2.2 Process control system design

The control system shall have a high reliability and shall be configured to fail safe.

Failure of all or a part of the process control system shall not cause a hazard situation.

Provisions shall be taken to reduce the consequences of component failure (i.e. common mode failure) for example:

— process equipment of a same function should be split between different processing modules;

— consequences of a common mode failure, plant-wide or local, shall be studied;

— data transmission routes shall be designed to maximize the reliability.

There shall be spare processing capacity and I/O modules available with the plant in full operation. Consideration should be given to have live spares available. In case of plant expansion, the spare processing capacity shall be restored.

Design reviews mentioned at 4.5.3 shall be performed on control systems. The acceptance procedures shall include confirmation of the safe operation of the process control system during malfunction and failure mode.

Remotely controlled equipment shall in case of an emergency or malfunction be capable of being stopped locally.

The process control system shall indicate, store and/or print all information returned by the process control devices necessary for the safe and efficient operation of the plant. In order to analyse an incident, the system shall chronologically discriminate and store all information occurred during this time and all actions performing by the operator before and after the event.

The process control system shall inform the operator of essential electrical facility information necessary to operate the plant.

The process control system design should present the operator with the optimum amount of data required for safe and efficient operation of the plant and shall minimize alarm overload in case of incident or a sudden state change.

14.3 Safety control system

14.3.1 Principle

The safety control system shall be designed for detecting hazard situations and reducing their consequences. It shall have the following functions as a minimum:

— gas detection (LNG, refrigerant gas, natural gas);

— spillage detection;

— fire detection;

— ESD activation from a central system and/or local ESD station;

— monitoring, activation and control of safety devices;

— monitoring and control of essential parameters to keep the installation in safety situation.

All modifications of safety control system shall be performed in compliance with the Safety Management System.

14.3.2 Emergency shut down (ESD) and safety actions

14.3.2.1 General

ESD activation shall cause equipment shut-down and ESD valves operation to their fail safe position in order to contain inventories.

All ESD actions shall be activated by the safety control system central panel with supplementary activation from local ESD stations. ESD activation shall neither cause a new hazard situation nor damage a machine or other equipment. Where there has been no response from the operator to Fire, Spill and Gas Detection System alarms, ESD activation in response shall be automatic from the fire, spill and gas Detection system after a suitable time delay. It is not the intention of this action to require the Fire, Spill and Gas Detection system to be a SIL rated system

This activation shall be transmitted to the process control system which shall operate in a manner complimentary to the ESD action. The process control system shall put automatic sequences in such a position as to prevent unexpected equipment or valve operation which may occur at the time of ESD reset.

Hazard assessment conclusions shall be applied to the design of the safety control system. Type, redundancy, number and location of detectors or sensors shall be studied to ensure quick and reliable detection of a hazardous situation. The system specification is derived from the requirements of the hazard assessment in 4.4.2. A cause and effect matrix shall be produced in compliance with hazard assessment and HAZOP study requirements.

The principle of the ESD operation shall be to minimize the release of hydrocarbons and to minimize the escalation of any hazardous event into adjacent areas.

Plants are often divided into fire areas and subdivided into fire zones to enable the ESD actions limiting escalation to be defined.

Fire hazards in a fire zone may be controlled by the operation of the ESD valves. The ESD shall isolate the fire zone to minimize the release of hydrocarbon from the fire zone, and to minimize the flow of flammable hydrocarbons into the fire zone to limit the fire event.

A fire zone may be depressurized after isolation by ESD valve operation to reduce hydrocarbon inventories and to minimize the potential for vessel failure or structural collapse due to the fire intensity and duration.

ESD valves are also used within fire zone to minimize the release of hazardous materials from vessels due to the failure of downstream equipment or piping.

ESD operation is usually provided as a structured response related to the hazardous event.

Typical ESD levels are:

— ESD 1: (un)loading shutdown;

— ESD 2: ship disconnection;

— ESD 3: process shutdown (liquefaction or vaporization). This ESD 3 could be organized to prevent total loss of operation, if applicable to the plant.

— ESD 4: Total Facility Shutdown: All equipment shut down.

14.3.2.2 ESD for marine transfer operations.

The use of ESD systems for the protection of marine transfer operations is well described in Ref 56 SIGTTO ESD Arrangements and Linked Ship/Shore Systems for Liquefied Gas Carriers which derives from IGC codes.

14.3.3 System capabilities

14.3.3.1 Main functions

The safety control system shall:

— initiate automatically the appropriate ESD actions. Manual activation only of an ESD system is only permitted when fully justified by the hazard assessment with the approval of the appropriate authorities;

— where appropriate, activate automatically the necessary protection equipment;

— inform the process control system of ESD activation;

- control visual and sound emergency communication devices defined in emergency plans (i.e. siren);
- open gates to allow access of emergency crew and staff evacuation, where required by emergency plans.

14.3.3.2 Safety Integrity Levels (SIL)

Since safety functions are designed to lead to a certain risk reduction safety integrity levels can be assigned to them.

The safety control system shall be designed and operated in accordance with requirements of EN 61508-1. SIL requirements shall be studied and evaluated to be consistent with the required plant safety level.

The ESD signal processor shall be SIL 3 or better.

14.4 Access control system

Access points for entering inside the plant boundary shall be controlled through separate, specially adapted barriers for vehicles and personnel. A minimum of two accesses shall be provided to facilitate access for firefighting and emergency vehicles.

Depending on the size of the plant, access to process zones where gas is stored, piped or processed shallbe controlled. Such control can be limited to process zones or extended to a wider area. Control of access can be put into practice either by security guards or by using a physical device (lock, magnetic badge, etc.).

14.5 Anti-intrusion system

The LNG plant shall be surrounded by a fence (see [29]) and could be equipped with an anti-intrusion detection system.

14.6 CCTV

This system should integrate a closed circuit TV system. It monitors process areas and accesses which present a risk (as mentioned in hazard assessment).

See 13.4: CCTV monitoring.

14.7 Jetty and marine monitoring and control

When following functions are available they should be interfaced in the plant monitoring and control system:

- monitoring of weather conditions (wind, sea situation, etc.);
- berthing monitoring (speed, distance, etc.);
- mooring monitoring (mooring loads, etc.);
- status of quick release hooks;
- monitoring and control of marine transfer arms;
- marine transfer arm Emergency Release System.

For details, see EN ISO 28460 and EN 1474 (all parts).

14.8 Communications

Internal transmission networks shall differentiate operation information (of process control system) from safety information (of safety control system). Internal transmission networks shall be made secure from external communication networks (no direct interfaces are recommended for manned plants).

14.9 Environmental monitoring and control

Emissions of the plant shall be monitored and controlled.

15 Construction, commissioning and turnaround

15.1 Quality assurance and quality control

A quality management system shall be applied to the following phases:

— organization;

— design and procurement;

— equipment, shop manufacture;

— equipment, storage and transport;

— construction, (earthworks, installation, backfilling, civil works and structural steelwork, storage tanks, pressure vessels, separators, furnaces, boilers, pumps, aboveground piping including supports, underground piping, instrumentation, electricity, cathodic protection, paint work, thermal insulation, fire proofing).

A specific quality control programme including inspection and tests shall be set up to monitor the quality throughout the different phases of the design, fabrication and construction.

As a minimum inspection certificates 3.1 according to EN 10204 shall be provided for pressure retaining parts of process equipment and/or system.

15.2 Acceptance tests

Equipment installed on the plant shall be tested in accordance with the relevant codes and standards especially for:

— high pressure pipe-work;

— pressure vessels;

— fired equipment.

For LNG tanks the tests shall be made in accordance with 6.14.

15.3 Preparation at start-up and shutdown

The presence of hydrocarbons and of low temperatures, requires special commissioning and shutdown procedures. These include, before start up:

a) inerting in order to eliminate oxygen to obtain a maximum oxygen content of 8 mol %;

b) and drying of the plant using one of the following:

1) a vacuum drying technique a good option for long jetty and run down lines but requires the piping to be designed to full vacuum;

2) nitrogen heated to 60 °C blown through the piping at low pressure and high volumetric rates. The nitrogen is exhausted to atmosphere. The advantage of this method is that purging is completed whilst drying;

3) drying with dried natural gas, ensuring that water has been eliminated at all points of the plant, including the connecting lines to instruments. The disadvantage of this method is the restraints that hydrocarbon brings to the plant. In case of closed refrigerant loops the dynamic de-riming using the compressors can speed up the process. The tanks are normally dried after hydro test with mops and space heaters to ensure there is no free water. Where in tank pump wells are fitted it is important to ensure there is no water held by the foot valves that could lead to the foot valve freezing and rendering that stilling well unusable. It is common practice not to fit the foot valve until after the hydro test.

The typically used limits for the dew point in the piping to target are – 40 °C.

At the time of any shutdown for servicing which requires opening of a circuit, it is necessary to:

— positively isolate the system;

— eliminate liquid hydrocarbons;

— defrost and warm to ambient temperature by circulating warm dry gas;

— and finally inert by purging with nitrogen before opening to atmosphere.

16 Preservation and corrosion protection

16.1 Painting

Corrosion protection of metal surfaces of equipment, pipelines and metallic structures in a LNG installation is required. Concrete structures may also be painted to protect them from wear and tear.

Surface preparation, paint systems and application of coatings to steel structures shall be according to EN ISO 12944 (all parts).

Salt-laden or aggressive atmospheres and operating conditions shall be taken into account when selecting coating systems.

High quality hot-dip galvanizing according to EN ISO 1460 and EN ISO 1461 is required on all platform and platform support steel work, stairway and handrail assemblies, ladder side rails and cages, plates, stair treads and open grid flooring, etc. unless impracticable. Tubular sections shall be galvanized internally and externally.

Galvanized surfaces may normally be left unpainted except for marine environment for which additional painting is recommended. Galvanized metal jackets used to cover insulation of piping or equipment can receive further anti corrosion coating. For zinc contamination of austenitic stainless steel, 4.5.2.1.i) should be considered.

For safety reasons all equipment and piping in LNG land based installations shall have a specific colour or marking for identification of the contents.

All painting, galvanizing, colour coding and marking shall be designed and executed in accordance with local rules.

16.2 Cathodic protection

See Clause 12.

17 Training for operations

The plant shall be operated in a safe and efficient manner compliant with national health and safety legislation.

Operating practices and procedures shall be compliant with the requirements of the Major Accident Prevention Policy and the Safety Management System including major accident prevention policy.

NOTE For example, requirements are based on the requests of the called "Seveso III" European Directive [Council Directive 2012/18/EC on the control of major-accident hazards involving dangerous substances] and the risk assessment of explosive atmospheres required by the "ATEX" Directive (1999/92/EC) [Directive 1999/92/EC of the European Parliament and of the Council of 16 December 1999 on minimum requirements for improving the safety and health protection of workers potentially at risk from explosive atmospheres] [20].

Written operating procedures shall be provided for the plant and be readily available for those operating the plant. These should cover all normal and emergency operating procedures.

Protective equipment (personal protection) shall be provided and worn as determined by risk analysis.

Operators involved in emergency activities shall be equipped with the necessary protective clothing and equipment. Portable flammable gas detectors shall be readily available.

Persons engaged in the management, production, handling and storage of LNG shall be trained in the hazards and properties of LNG with particular attention to emergency response procedures.

Operation and maintenance staff shall be well trained in all aspects of their work to ensure that they can work in a safe and competent manner under both normal and emergency conditions. Initial training should take into account the background of the individual. Re-training should be undertaken at regular intervals and all records of their training kept.

For management and staff, training schemes should be structured according to the individual's experiences, duties and responsibilities within the organization and independently validated.

All persons visiting a site for whatever purpose shall be instructed in the hazards and properties of LNG, the depth to which this training is undertaken shall be appropriate to their level of involvement in site operations.

18 Pre-operational marine training

In all projects, there should be consultation between the terminal owner, port operator, ship operator, pilots and tug-masters. Pre-operational training and regular refresher courses, using simulators, should be undertaken, involving all relevant parties.

See [23].

Annex A
(normative)

Thermal radiation threshold values

A.1 Heat radiation from LNG fires

Table A.1 gives the recommended maximum incident radiation flux values in case these are not already defined in the local regulations. The radiation flux from an LNG fire shall be calculated using appropriate and validated models (some available methods are presented in EN ISO 16903 or [19]).

In any case, the maximum radiation flux levels acceptable for each main structure inside boundaries shall be confirmed using validated methods and using the curves defined in the parts of EN 1991, EN 1992, EN 1993 and EN 1994 listed in Clause 2. The designer shall justify the maximum thermal radiation flux level used by calculating the surface temperature consistent with the expected duration of the fire to show that it is sufficiently low to maintain the integrity of the structure. The nature and the mechanical behaviour of the materials with respect to temperature shall be taken into account in the calculation.

For LNG storage tanks, the permissible radiation flux shall be determined taking into consideration the following factors as a minimum:

— credit can only be taken for water cooling of the tank if the means of applying the water can be operated from a safe area;

— loss of strength of container;

— pressure built up within the container;

— capacity of the safety valves;

— surface emissive powers (see EN ISO 16903).

Table A.1 — Allowable thermal radiation flux excluding solar radiation inside the boundary

EQUIPMENT INSIDE BOUNDARY	MAXIMUM THERMAL RADIATION FLUX (kW/m²)
Concrete outer surface of adjacent storage tanks [a]	32
Metal outer surface of adjacent storage tanks (see [3])	15
The outer surfaces of adjacent pressure storage vessels and process facilities (see [3])	15
Control rooms, Maintenance workshops, laboratories, warehouses, etc. (see [2])	8
Administrative buildings (see [2])	5
[a] For pre-stressed concrete tanks, maximum radiation fluxes may be determined by the requirements given in A.1.	

The heat flux level can be reduced to the required limit by means of separation distance, water sprays, fire proofing, radiation screens or similar systems.

Table A.2 gives the recommended maximum incident radiation flux values in case these are not already defined in the local regulations.

Table A.2 — Allowable thermal radiation flux excluding solar radiation outside the boundary

OUTSIDE BOUNDARY	MAXIMUM THERMAL RADIATION FLUX (kW/m²)
Remote area [a]	8
Critical area [b]	1,5
Other areas [c]	5

[a] An area only infrequently occupied by small numbers of persons, e.g. moor land, farmland, desert.

[b] This is either an unshielded area of critical importance where people without protective clothing can be required at all times including during emergencies or urban area (defined as an area with more than 20 persons per square kilometre) or a place difficult or dangerous to evacuate at short notice (e.g. hospital, retirement house, sports stadium, school, outdoor theatre).

[c] Other areas typically include industrial areas not under control of the operator/occupier of the LNG facilities.

NOTE The figures used in Table A.2 are taken from [2]: Effect of fire radiation on pre-stressed concrete.

The thickness of the concrete shall be sufficient to ensure that, in the event of an external fire, the temperature of the pre-stress cables is kept low enough to maintain the integrity of the LNG tank and its enclosure with full contents and at maximum design pressure. If no water deluge system is installed, the integrity of the design of the tank shall be guaranteed during the time needed to provide fire water in sufficient quantities from an external source. To determine the minimum concrete thickness recognized methods and appropriate models which have been validated shall be used.

A.2 Heat radiation from flare or ignited vent stack[6)]

Table A.3 and Table A.4 give the recommended maximum incident radiation flux values in case these are not already defined in the local regulations. The predicted values used for the comparison can be calculated in accordance with [3].

However, alternative methods for prediction of flux level can be acceptable. In this case the designer shall justify that the method proposed is validated.

Table A.3 — Allowable thermal radiation flux excluding solar radiation inside the boundary

EQUIPMENT INSIDE BOUNDARY	MAXIMUM THERMAL RADIATION FLUX (kW/m²)	
Flow rate as defined in 11.6	Normal	Accidental
Peak within the sterile area (see [3])	5	9
Outer edges of restricted (sterile) area	NA	5
Roads and open areas	3	5
Tanks and process equipment	1,5	5
Control rooms, maintenance workshops, laboratories, warehouses etc.	1,5	5
Administrative buildings	1,5	5

6) In risk assessment, the vent ignition is assumed a credible event.

Table A.4 — Allowable thermal radiation flux excluding solar radiation outside the boundary

OUTSIDE BOUNDARY	MAXIMUM THERMAL RADIATION FLUX (kW/m²)	
Flow rate as defined in 11.6	Normal	Accidental
Remote area [a]	3	5
Critical area [b]	1,5	1,5
Other areas [c]	1,5	3

[a] An area only infrequently occupied by small numbers of persons, e.g. moor land, farmland, desert.

[b] This is either an unshielded area of critical importance where people without protective clothing can be required at all times including during emergencies or a place difficult or dangerous to evacuate at short notice (e.g. hospital, retirement house, sports stadium, school, outdoor theatre).

[c] Other areas typically include urban and industrial areas not under control of the operator/occupier of the LNG facilities.

NOTE The figures used in Tables A.3 and A.4 are derived from [3] and [4].

Annex B
(normative)

Definitions of reference flow rates

B.1 General

The various flow rates of gaseous discharges are defined below.

B.2 V_T (heat input)

The V_T maximum flow rate of a tank ("boil off") due to heat input in normal operation is to be determined by assuming ambient air at the maximum temperature observed in the course of a hot summer day.

B.3 V_L (fluid input)

Filling of the tank generate a piston effect. The maximum volume flow rate for tank filling is to be taken for the value of V_L the resulting gas volume flow rate (expressed under the actual conditions of temperature and pressure in the gaseous crown of the tank).

V_L is the highest flow rate possible with the inlet control valve failed open.

B.4 V_O (over filling)

If over filling leading to spillage of LNG into the annular tank space cannot be excluded, the instantaneous vaporization of the LNG entering the tank shall be considered. The steps taken in 6.7.2 can be reinforced as required.

B.5 V_F (flash at filling)

At LNG filling of the tank, instantaneous vaporization occurs (called "Flash"). The main reasons of LNG flash are the following:

— heating of the LNG due to the pumping;

— heat input from piping during loading or unloading;

— cooling of the tank wall when the liquid level increases, (due to the fact that the temperature of the vapour phase of the above part of the tank is higher than the temperature of the liquid, consequently the wall tank is cooled down when the level of LNG increases producing vaporization);

— mixing of the LNG already stored;

— when the pressurized LNG sent into the tank has a temperature before expansion higher than that of the bubble point of the liquid at tank pressure, instantaneous vaporization occurs.

V_F, volume of the flash at filling shall be at the maximum filling rate with the control valve failed open and shall be determined including all the above parameters.

If the LNG was initially at equilibrium, the fractional proportion of liquid which vaporizes instantaneously (F) due to a temperature before expansion higher than that of bubble point of the stored LNG can be calculated rigorously or approximated by the following simplified equation:

$$F = 1 - exp\left[\frac{C(T_2 - T_1)}{L}\right]$$

where

C is the heat capacity of the fluid (J K^{-1} kg^{-1});

T_2 is the boiling-point temperature of the fluid at the pressure of the tank (K);

T_1 is the temperature of the fluid before expansion (K);

L is the latent heat of vaporization of the fluid (J kg^{-1}).

Consequently V_F is calculated using the following equation:

$$V_F = F \times filling\ flow\ rate\,(in\ kg/s)$$

In the absence of more precise data, if the drop of absolute pressure is less or equal to one bar, the following values can be used:

$$C = 3{,}53 \times 10^3 . JK^{-1} . kg^{-1} \ ;$$

$$L = 504 \times 10^3\, Jkg^{-1} \ ;$$

$$(T_2 - T_1) = (p_2 - p_1)/8000 \ ;$$

where

$(p_2 - p_1)$ expressed in Pascal, represents the absolute pressure reduction of the LNG between the initial storage and the pressure of the destination tank.

B.6 V_R (LNG recirculation by a submersible pump)

V_R represents the mass flow rate of boil-off brought about by internal recirculation of the LNG by the largest of the submersible pumps.

V_R can be estimated using the simplified following formula taken into consideration the assumption that all the energy of the pump goes into the fluid:

$$V_R = Energy\ input\ per\ pump\ /\ L.$$

The energy is expressed in J/h and L in J/kg (see B.5).

B.7 V_A (variation in atmospheric pressure)

If the pressure in the tank is equal to maximum operating pressure, a drop in atmospheric pressure brings about a gaseous discharge from expansion of vapour in the crown (V_{AG}) plus vapour evolved from the overheat of the liquid (V_{AL}). Similarly a vacuum condition can arise following an increase in atmospheric pressure.

V_{AG} the flow rate due to vapour expansion can be calculated using the following formula (V_{AG} expressed in m³/hour under actual conditions of pressure and of temperature of the gaseous crown sheet):

$$V_{AG} = \frac{V}{p} \times \frac{dp}{dt}$$

where

V is the maximum gaseous cubic capacity of empty tank (m³);

p is the absolute operating pressure (Pa);

dp/dt is the absolute value of rate of variation in atmospheric pressure (Pa/h);

V_{AL} the flow rate due to the de-superheating of liquid can be estimated by adapting the methods given above in B.5 for the calculation of *F*.

$$V_A = V_{AG} + V_{AL}$$

Local data for rate of atmospheric pressure change shall be used. Where there is no local data available a drop in atmospheric pressure of 2 000 Pa/h with total variation of 10 kPa can be assumed.

This value also enables the calculation of the incoming volume of flow in the event of an increase in atmospheric pressure.

B.8 V_V (control valve failure)

Failure of a control valve can lead to increased vapour loads as for example from a suddenly increased filling rate or untimely opening of a vacuum breaker valve.

B.9 V_I (heat input in the course of a fire)

The rate of evaporation in the course of a fire is determined by assuming that incoming heat is used immediately for vaporizing the fluid taking no credit for the effect of firewater.

The heat flow received by the vertical external enclosure of the tank is assumed, by default, to be equal to the emissive power of a flame of LNG (see EN ISO 16903).

This value is overruled by the worst case value of heat radiation in the hazard assessment for the actual location of the tank.

B.10 V_D (fluid suction)

Withdrawal of liquid shall be offset by a gaseous input in order to prevent negative pressure. The volume flow rate of gas is taken to be equal to the maximum volume flow rate of the suction pumps.

B.11 V_C (compressors suction)

Natural evaporation which occurs in the tank is generally removed by boil off gas compressors. Even though the suction volume flow rate of such compressors is adjusted in normal working conditions to fit the rate of evaporation, the possibility that the compressors will cause negative pressure in the tank cannot be excluded. V_C represents the maximum suction volume flow rate of the compressors.

B.12 V_B (roll-over)

The boil off due to a roll-over shall be calculated using appropriate validated models.

In case where no model is used, the flow rate during roll-over shall be conservatively taken equal to:

$$V_B = 100 \times V_T$$

This flow rate corresponds approximately to the maximum flow rate observed in the past during a real roll-over.

Annex C
(informative)

Seismic classification

C.1 Introduction

This annex provides a methodology for the seismic classification of plant and equipment to allow the design of the plant to provide the correct level of earthquake resistance to an earthquake event as defined in 4.5.2.2.

C.2 Some basic principles

— The seismic classes are defined in 4.5.2.2.

— The plant should be shutdown after any earthquake the magnitude of which exceeds a value less than the OBE acceleration value (this value to be specified by the owner/operator).

  This shutdown decision can be operator initiated, or automatically from seismic detectors to facilitate an orderly shutdown rather than a random trip of machinery caused by individual vibration detection devices.

— A full safety inspection shall be carried out prior to resuming operation to check:

  — operability;

  — integrity;

  — stability.

— After OBE, all equipment and/or systems shall remain operational, except, if agreed by owner/operator, that equipment and/or systems that are not necessary for plant operation.

— After SSE, the plant is in a safe condition. In the period following the event additional measures may need to be taken to ensure safe reinstatement or, if necessary, decommissioning of the plant. These operations could take weeks or months.

— The Safety Management System shall describe the emergency procedures to be activated after SSE, allowing for availability of staff, for plant monitoring, inspection and to undertake temporary measures.

C.3 Example of safety approach after SSE

Local small leaks are accepted but the plant should keep its integrity to avoid additional hazard from hydrocarbon spillage.

The Central Control Room (CCR) becomes the operational crisis centre.

It is accepted that the CCR would not receive full plant operational information but major information, i.e. pressure, level and temperature on large hydrocarbon inventories, such as storage tanks and refrigerant containers, should be reported in the CCR.

To achieve this requirement after SSE, consideration should be given to separate hard wiring and routing of critical signal and control cables outside of plant structures that may be subject to damage during seismic activity.

The tank pressure control should be remotely controlled and safety valves should remain operational after SSE.

C.4 Example of classification for SSE

Based on the basic principles and the example of safety approach the following classification could be prepared:

Table C.1 — Seismic criteria classes

Criteria class	Operational functionality	Integrity	Stability
Class A	X		
Class B		X	
Class C			X

The different classes should include:

— Class A:

  — firefighting equipment and system (only for local operation);

  — underground fire water loop up to sprinkler valves and including hydrants;

  — ESD valves;

  — operability of the safety control system in the CCR;

  — UPS related to the safety control system;

  — critical signal to be reported in CCR;

  — hydrocarbon tanks pressure safety valves or control valves;

  — secondary container of LNG tanks;

— Class B:

  — all equipment and piping systems containing hydrocarbon or other hazardous medium (which rupture could bring potential for hazard);

  — all structures supporting such equipment and piping systems;

  — primary container of LNG tanks;

— Class C:

  — all non-class A or B items that are in the vicinity of A or B items and which collapse could impact class A or B items.

Annex D
(normative)

Specific requirements for LNG pumps

D.1 Introduction

This annex defines additional requirements to the ones described in Clause 7.

D.2 Design

The design shall meet the following specifications:

— thermal transient operating conditions shall be taken into account (see EN ISO 16903);

— flanges, gaskets and fasteners (nuts and bolts) for the joint shall be in accordance with recommendations given in 9.5;

— flanged joints shall be tested in accordance with EN 12308.

The manufacture and assembly shall meet the following requirements:

— provisions shall be made that fasteners remain tight due to the effect of temperature change or vibration;

— traces of oxidation and other contaminants shall be removed prior to fabrication or assembly;

— welding processes and procedures, quality of the electrodes, wires and flux shall be in accordance with EN ISO 15607, EN ISO 15609-1 and EN ISO 15614-1.

The unit shall be fitted with a system for compensating the residual axial thrust of the pump under all operating and transient conditions.

D.3 Inspection

D.3.1 General

To ensure the safety behaviour, pump components subjected to mechanical, rotational and thermal stresses shall be inspected and tested. Inspection and tests shall be performed in accordance with the relevant standards.

The pump manufacturer shall set up, in compliance with the owner requirements, a quality plan with a full inspection programme which shall include the inspection defined in D.3.2 to D.3.8 where applicable. The requirements for positive material identification shall be stated in the quality plan.

The manufacturer shall demonstrate the reliability of the applied procedure in accordance with the referred standard and the adequacy of the selected criteria with regard to the required quality level.

D.3.2 Inspection of components submitted to pressure or rotation

The chemical analyses and the mechanical characteristics shall be supplied for each casting.

For forged or rolled parts, mechanical tests shall be performed after any heat treatment. For each component, the supplier shall specify the reference standards, the sampling location and its direction.

D.3.3 Radiographic inspection

Radiographic inspection shall be conducted in accordance with EN ISO 9712 and EN ISO 17636-1 and EN ISO 17636-2.

D.3.4 Ultrasonic inspection

Ultrasonic inspection shall be conducted in compliance with EN ISO 9712 and EN ISO 17640.

D.3.5 Crack detection (dye penetrant inspection)

Dye penetrant inspection shall be conducted in accordance with EN ISO 9712, EN ISO 3452-1 and EN ISO 17637.

D.3.6 Visual inspection

Visual inspection shall be carried out in order to check the compliance of the products supplied with the specifications of 7.2 and the individual component marking in accordance with the quality plan.

D.3.7 Dimensional inspection

The dimensional inspection shall be carried out in order to check whether the products supplied comply with the standards applicable to the supplier's plans and to the documents he shall give to the owner.

D.3.8 Electrical inspections

The following inspections shall be carried out:

— electrical tests in accordance with the quality plan;

— an electrical balancing test.

Electrical components shall be certified in accordance with the appropriate hazardous area classification.

D.4 Testing

D.4.1 Test condition

All the following tests, which are given hereafter, shall be conducted either with liquid nitrogen or with LNG unless otherwise stated.

Acceptable alternative test liquids can be used with the owner's agreement.

For all test liquids other than LNG, detail procedures and formulae shall be agreed between the manufacturer and the owner to predict the actual performance from the test data.

D.4.2 Type tests and acceptance tests

Type tests are carried out on the first of each pump type. Acceptance tests are carried out on all pumps of this design. Type tests shall include the following:

— mechanical strength and tightness tests (hydrostatic tests);

— performance tests;

— net positive suction head (NPSH) tests (the definition of NPSH is given in EN ISO 9906);

— cold rotation tests at a maximum temperature of − 160 °C (for pumps not tested with LNG).

Acceptance tests shall include at least the strength and tightness tests.

By special agreement with the pump supplier, the acceptance tests can also be extended to performance and NPSH tests. Acceptance tests shall be carried out either at the manufacturer's premises if the latter disposes of a test bench, or at a location decided by mutual agreement between the manufacturer and the owner/operator.

D.4.3 Strength and tightness tests

The pump body and any part of the pump under pressure (i.e. working barrel), shall undergo a strength test and a tightness test in accordance with EN 12162. Water can be used for these tests provided that chloride content is lower than 50×10^{-6} (50 ppm).

D.4.4 Performance tests

Performance tests shall be carried out preferably with LNG, the composition of which shall be specified and density and temperature shall be measured.

Test data shall be recorded or calculated, at least for six points of the operating range among which:

— shutoff flow rate;

— minimum continuous stable flow rate;

— two points in midway between minimum and rated flow rate;

— rated flow rate;

— maximum allowable flow rate.

The tests shall be conducted at the pump's nominal speed ± 3 % when LNG or at appropriate speed in the case of another medium, to be agreed with the owner.

For each of the flow rates except shutoff, the following parameters are determined:

— total hydraulic head at discharge;

— total hydraulic head at suction;

— pump efficiency and efficiency of the motor;

— power absorbed by the motor;

— vibration level;

— noise level.

For shutoff point, the following parameters are determined:

— total hydraulic head at discharge;

— power absorbed by the motor, if appropriate.

For pumps fitted with variable speed drivers, these parameters are also recorded at two different speeds of operation band (medium and minimum speed).

For a vertical motor pump submerged in the tank, a "pump down" test shall be carried out, the conditions of which shall be submitted for the owner's approval. Pump down test is a test of the pump at low liquid level equivalent to a reduction of discharge head to 40 % of the nominal value.

A continuous running test of minimum 1 h shall be conducted at rated duties.

D.4.5 NPSH tests

Measurements of the NPSH required by the pump shall be carried out at the equilibrium temperature of the liquid, preferably with LNG, the composition of which shall be specified, and at least 3 different flow rates for the first pump whilst only one for the other with same design. These flow rates shall be identical with those of the performance tests.

D.5 Declared values

For a liquefied natural gas, the density of which shall be specified at the reference temperature, the manufacturer shall declare the following values:

— differential head at shutoff;

— differential head at the minimum flow rate of the operating range;

— differential head at the nominal flow rate;

— differential head at the maximum flow rate of the operating range;

— NPSH required at the minimum flow rate of the operating range;

— NPSH required at the nominal flow rate;

— NPSH required at the maximum flow rate of the operating range;

— power consumption at the nominal flow rate;

— pump efficiency at the nominal flow rate and of its drive and speed converter, if any;

— pump down level in the case of an in tank pump (see D.4.4);

— power consumption at the minimum continuous and maximum flow rates.

The tolerances on these values determined during the course of the performance tests (see D.4.4) shall be as specified in EN ISO 13709.

D.6 Marking

A metal identification plate showing the following information should be fixed to each pump and working barrel:

— supplier's distinguishing abbreviation;

— manufacturing serial number and owner's order number;

— nominal flow rate (in m^3/h);

— nominal head of the pump (in metres);

— rotation speed at the nominal flow rate (in min^{-1});

— maximum working pressure (in bar gauge) and the date of testing of the working barrel, if any;

— date and pressure of pump test (see EN 12162).

D.7 Particular requirements for submerged pumps and related cables

D.7.1 Pot (can) mounted pumps

An electrical junction box shall be used for the connection between the electric cables of the pump and the external cables.

Due provision shall be made to avoid any gas migration from the suction pot into the junction box.

The cryogenic electric cables for the connections between the junction box and the pump motor shall withstand a working temperature of – 196 °C.

D.7.2 Column mounted (in tank) type

D.7.2.1 General

With a proper procedure, column mounted type pumps can be removed from the storage tank whilst it is in service. The pump and electrical cable assembly is inserted into the upper end of the pump column. The pump is sealed onto an adapter at the base of the column.

Suction is through the base adapter and discharge on the periphery of the pump body, between the column and the pump body.

In addition to the requirements of Clause 7 and D.2, the pump unit shall be able to be installed and removed by means of a lifting system using either dedicated cables or a set of connecting stainless steel tubes or some other means.

The column head plate seals the column. It shall comprise:

— on the inside: a tensioning system for the cable which secures the electric cables and the lifting cable coiled under the plate;

— on the outside: the electric cable junction box.

The base adapter shall ensure pump alignment in the centre of the column and prevent it from rotating. It shall allow the pump to be raised without requiring the application of any abnormal force.

D.7.2.2 Dedicated cables

The devices for handling the unit and for securing the cables shall include:

— a lifting system for the safe lowering and raising of the pump, without risk of falling and without twisting of cables;

— a spare lifting cable that will take over the function of the duty cable, in case of its failure; this spare cable shall be installed in such a way that it will prevent pump falling in case of duty cable failure. This spare lifting cable could only be discarded if owner/operator can demonstrate otherwise;

— an electrical support cable used for keeping the electrical cables under tension in the column, this cable shall be non-twisting type and shall be pre-stressed before assembly to avoid possible over stressing of the electrical cables due to temperature difference in the tank;

— a system for guiding the cables into the column;

— a system for supporting a measurement cable stemming.

The electric cables shall have a bending radius which allows easy handling while avoiding breakage under the cable's own weight.

D.7.2.3 Stainless steel tubes

Where stainless steel tubes are used a shut-off device (a gate valve, or spectacle type blind flange, or any other suitable closing device) may be placed on top of the column outside the tank.

The pump shall be lifted by a set of connecting stainless steel tubes which also contain the electric power supply cables. This lifting mechanism shall be rigid, easy to assemble and shall protect the electric cables.

D.8 Vertical external motor pumps

The unit comprises an electric motor/centrifugal pump assembly.

The vertical pump is installed in a barrel with the pump submerged in the LNG. The electrical motor is mounted on top of the barrel and is not submerged in the LNG.

Careful consideration shall be given to sealing arrangements. Shaft sealing shall eliminate leakage past the seal.

The cooling down of the pumps shall be carried out slowly and carefully. Each pump shall be provided with an adequate vent or relief valve to prevent over-pressure during cool-down.

The barrel shall be insulated in order to prevent vaporization and to inhibit condensation. The foundations of the pump shall be designed and constructed to prevent frost heaving.

Annex E
(normative)

Specific requirements for LNG vaporizers

E.1 Operating parameters/declared performance

The operating parameters of vaporizers for which the nominal values are to be specified according to type are given in Table E.1. The range within which these parameters will be able to vary shall also be specified.

Certain of these values shall be declared by the manufacturer. More specific requirements are given below.

E.2 Water stream vaporizers: Open rack type (ORV)

E.2.1 Specific design requirements

Open rack vaporizers shall be protected against adverse atmospheric conditions such as wind, snow and rain. In particular, wind shield should be provided to limit sea water foam dispersion by the wind.

The two following variable actions shall be considered in the determination of the normal action used for design:

— exceptional thermal stress resulting from poor distribution of water e.g. a heating tube is not wetted;

— accumulation of ice (10 cm thick) on half the height of the vaporizer.

E.2.2 Water distribution

Flow of water shall be even:

— on the different accessible parts of any section of tube in order to prevent distortions of the tube;

— between different tubes which are mechanically connected.

The system for distribution of water over the tubes should be easily accessible, adjustable and designed to permit cleaning, if required by the owner without interrupting operation, using one of the following methods:

— jet of water;

— blast of air under pressure;

— rodding brush.

Table E.1 — Values to be specified for LNG vaporizers

			Water stream: open rack	Water stream: closed	Intermediate fluid: atmospheric water bath	Intermediate fluid: forced flow	Intermediate fluid: condenser vaporizer	Submerged combustion	Atmospheric vaporizer
Basis parameters		Minimum and maximum intermediate fluid flow rate				X			
		Minimum and maximum intermediate fluid pressure				X			
		Minimum and maximum throughput	X	X	X	X	X	X	X
		Maximum utility consumption						X	
		Minimum heating fluid temperature	X	X	X	X		X	
		Maximum heating fluid temperature			X	X			
		Minimum outlet temperature vaporized gas	X	X	X	X	X	X	X
		LNG/NG pressure drop	X	X	X	X	X	X	X
Operating parameters	Service utilities	Minimum air temperature, wind speed, and humidity							X
		Minimum water inlet temperature	X	X	X				
		Water flow rate	X	X					
		Water outlet temperature	X	X	X				
		Combustion gas pressure, temperature, composition						X	
		Water analysis	X	X	X			X	
		Pressure range of intermediate fluid				X	X		
		Type of intermediate fluid			X	X	X		
		Battery limit conditions for utilities	X	X	X	X	X	X	X
		Type of heating			X	X	X		
	LNG	Heating curves	X	X	X	X	X	X	X
		Thermal duty	X	X	X	X	X	X	X
		Inlet and outlet temperature	X	X	X	X	X	X	X
		Inlet and outlet pressure	X	X	X	X	X	X	X
		Composition	X	X	X	X	X	X	X
		Mass flow rate	X	X	X	X	X	X	X
	General	Minimum time to start up	X	X	X	X	X	X	X

E.2.3 LNG and NG lines

Stress analysis shall be performed on both LNG inlet lines and NG outlet lines to allow proper flexibility and minimize loads on panel connections.

E.2.4 LNG distribution

Care shall be taken with the distribution of the LNG flow between parallel vaporization channels. One solution consists of having a generously dimensioned manifold and a restriction at the inlet of each exchanger tube.

E.2.5 Cleaning of the LNG/NG circuit

Gas circulating in the exchanger can contain paraffin waxes. These deposit on the sidewalls of tubes and reduce the performance of vaporizers. In that case, a facility for flushing tubes with the aid of a suitable solvent shall be provided. The solvent used shall be compatible with the materials used.

E.2.6 Control/safety

Safe operation is achieved by the control of the vaporizer gas outlet temperature and water flow rate, which form the basis of the alarm and safety system.

In case of low gas outlet temperature or low water flow the vaporizer shall be automatically isolated. Gas outlet valve closure time should be set to prevent cold temperature extending over limits defined by thermal transient analysis (see 8.1.2).

Threshold values for gas outlet temperature shall be defined. Typical values might be:

— 0 °C for alarm;

— – 5 °C for operation of safety shutdown devices to stop LNG feed.

Where the minimum ambient temperature is below the trip threshold, start up of the vaporizer can require a carefully designed override.

Insufficient flow of water shall be automatically detected (e.g. flow sensor).

E.2.7 Shelters for vaporizers

If revamping of the coating of finned tubes requires dismantling of components, the building shall be designed accordingly, i.e. with a removable roof.

Any side panels shall be designed to prevent any projection of water to the outside (water shall be returned to the lower reception basin).

Inspection traps systems shall be provided to permit inspection in operation.

E.2.8 Water circuits

Water circuits (pumps, pipe-work, water heating, chlorination) are to meet the requirements listed in 12.5.

E.2.9 Water quality

The water quality shall be checked for compatibility with tube material.

When water contains fines and solid particles, the vendor should recommend the most appropriate protection such as water filtration.

E.3 Water stream vaporizers : Closed type (STV)

The flow rate and the temperature of the water shall be controlled.

Vaporizers shall be operated with tube surface temperatures above 0 °C, so that formation of ice will be avoided. During upset conditions, when water throughput is insufficient, the supply of LNG shall be reduced or stopped. If necessary, water shall be drained from the shell side of the heat exchanger.

Threshold values for gas outlet temperatures shall be defined. Typical values might be:

— + 15 °C, for alarm;

— + 10 °C, for operation of safety shutdown devices to stop LNG feed.

The water flow rate shall be temperature controlled. In order to avoid blockage, an additional water flow rate detector shall be installed to stop throughput of LNG in case of insufficient water flow.

E.4 Intermediate fluid vaporizers (IFV)

E.4.1 Atmospheric water bath type

Control shall be based on the temperature of the water bath. If an external pump is used for forced circulation of the water, the non-availability of this pump shall be considered and should cause a unit shutdown.

Threshold values for gas outlet temperatures shall be defined. Typical value might be:

— + 15 °C, for alarm;

— + 10 °C, for shutdown.

The water bath temperature shall be controlled by the heat supply. In the event of heat supply shut down, the LNG feed shall be stopped.

E.4.2 Forced flow type

The principles of control are similar to those of the closed water stream vaporizer with the difference that the set point of the alarms and shut down are dependent on the physical properties of the intermediate fluid.

The outlet temperature of the vaporized LNG controls the flow rate of the intermediate fluid in the circuit. In case of upset conditions of the intermediate fluid circuit the LNG throughput shall be stopped.

E.4.3 Condenser/vaporizer type

Condenser vaporizer systems are temperature controlled. LNG is vaporized against intermediate fluids. Alarm and shutdown functions shall be dependent on physical properties of the intermediate flow and equipment design conditions.

The temperature controller of the vaporized LNG at the outlet of the vaporizer shall act on the heating source of the system.

E.5 Submerged combustion type vaporizers (SCV)

E.5.1 Corrosion

The selection of material and design of the vaporizer should avoid corrosion.

Water pH should be regularly monitored to avoid tube pitting corrosion.

Care shall be taken with the anti-corrosion treatment of components made of carbon steel (stacks, supports, etc.) due to the potential acidic environment.

E.5.2 Control and safety

The use of a programmable controller is preferred.

The primary parameter governing the operation of the burner is the gas outlet temperature, however the water bath temperature should be low enough for good energy efficiency but sufficiently high to prevent freezing.

The parameters governed by the automatic burner control system are the flow rates of fuel gas and air.

A submerged combustion vaporizer should include a pilot flame. The control system shall distinguish three steady state operating modes for the pilot:

— shutdown;

— standby (only the pilot flame is on);

— normal operation.

Flame sensors monitor permanently the presence of a flame during "standby" and "normal operation".

Safety devices which could initiate shutdown of the equipment are to be the following, as a minimum:

— too low bath water temperature;

— too low gas outlet temperature;

— too low bath level;

— extinction of flame;

— gas detection in the incoming air;

— air fan tripping.

Threshold values for gas outlet temperature, shall be defined. Typical values might be:

— 0 °C for alarm;

— -5 °C for shutdown of a vaporizer or of a set of vaporizers, according to the position of the temperature probe within the gas circuit.

Where the trip threshold is above the minimum ambient temperature, start up of the vaporizer can require a carefully designed override.

In the event of trip, the control systems shall automatically:

— isolate the LNG supply to that vaporizer and protect downstream pipe-works from low temperature;

— cut off the gas supply to the pilot and main burners;

— maintain the operation of the fan and the water circulating pump (account shall be taken in the design of the fact that water can enter the fume distribution casing and the enclosure of the burner when the fan stops, causing major thermal shock and possible damage to those parts of the equipment);

— deliver an alarm signal to the appropriate control room.

E.5.3 Water bath

The construction material of the water bath shall be able to withstand the acidity of the water which results from the dissolving of fumes (carbon dioxide, nitrogen oxides) in the water. The water bath shall be leak tight.

The position of the overflow should take into account the large increase in the water level which occurs between shutdown and operation of the equipment.

E.5.4 Vibration

Fumes going through the bath generate vibration and account shall be taken of this in the design.

E.5.5 Arrangements for cold periods

Winterization shall be considered in the design of the vaporizer.

E.5.6 ELegionella

The operation of the water bath shall consider that the conditions for legionella and bacteria to develop may exist. The operator shall have a program in place to test for legionella and a plan to avoid a growth of the bacteria.

E.6 Ambient air vaporizers (AAV)

Ambient air vaporizers use air as heating medium either with natural or forced draft.

Both Types of AAV (natural or forced draft) require defrosting cycles, producing vast amounts of freshwater.

The AAV system produces misting or 'fogging'. Therefore the adverse effect by fogging on the area surrounding the Terminal needs to be determined. The likelihood of when fog formation will occur and its dispersion shall be studied through CFD Model Analysis or similar method, which will indicate when the fogging will occur and the effect of its dispersion.

The adverse effect of the fogging has also to be considered for the vaporizer performances (availability of ambient temperature air) and for the safety (visibility, efficiency of the detection systems).

Annex F
(normative)

Criteria for the design of pipes

The following actions shall be considered for the calculation of supports and flexibility:

- permanent criteria:
  - internal pressure;
  - weight of tube;
  - weight of lagging, etc.;
- variable criteria:
  - intermittent loads due to hydraulic shock;
  - thermal loads, due to the contraction and fatigue phenomena following cycles of cooling and heating; particular attention is required in the case of a sudden change of thickness or diameter;
  - snow;
  - wind;
  - earthquake, etc.

The criteria linked with hydraulic hammer are the result of maximum over-pressure created by undue stopping of a pump or the closing of a valve. These actions shall be determined using a method which has been validated by experimentation with LNG. As a first approximation the following simplified formulas may be used to calculate the values of over-pressure due to the valve closing expressed as a LNG column height, i.e. D_h:

$$t \leq \frac{2L}{v}, D_{\mathrm{h}} = \frac{v V_{\mathrm{o}}}{g}$$

$$t > \frac{2L}{v}, D_{\mathrm{h}} = \frac{2L V_{\mathrm{o}}}{g\,\mathrm{t}}$$

where

L is the length of pipeline;

t is the closing time of the valve;

v is the shock wave speed, $v = 1\ 500\ \mathrm{ms}^{-1}$ for LNG;

D_{h} is the height of the LNG column equivalent to the over-pressure;

V_0 is the flowing velocity of LNG before hydraulic hammer;

g is the acceleration due to gravity.

Lines subject to surge loads and close to their limit state conditions shall be designed by FE-methods considering cavitation effects.

Annex G
(informative)

Description of the different types of onshore LNG installations

G.1 LNG liquefaction plant

LNG liquefaction plants generally include:

— an incoming natural gas metering and receiving station, including in the case of a two phase incoming pipeline, a slug catcher;

— condensate stabilization and storage;

— gas treatment units in which any acid gases, water, heavier hydrocarbons and, if appropriate, mercury which might be present in the incoming gas are extracted;

— liquefaction units which produce LNG and within which, ethane, propane, commercial butane, heavier hydrocarbons and nitrogen can be extracted. A proportion of the extracted hydrocarbons can be used as refrigerant make up. A liquefaction unit uses very specific equipment such as cryogenic spool-wound or brazed plate-fin exchangers and high-powered turbo-compression units. Two refrigerant cycles in cascade are usually employed;

— LNG storage tanks and the relevant loading facilities for filling LNG carriers, trucks, etc. where appropriate;

— Liquefied Petroleum Gas (LPG) and/or natural gasoline storage tanks, if appropriate, and the relevant loading plants;

— generation and/or purchase and distribution of the utilities necessary for the plant to operate (electricity, steam, cooling water, compressed air, nitrogen, fuel gas, etc.);

— and general off-site installations, (gas and liquid flare systems, effluent treatment, firefighting systems, etc.).

Most of the gas treating steps can be commonly found in gas treatment plant for the production of sales gas, e.g. acid gas removal, dehydration, hydrocarbon dew point and natural gas liquid (NGL) recovery. NGL fractionation is also commonly found in the light ends unit of oil refineries.

It can be noted, apart from the storage tanks, only a fraction of the hydrocarbons contained within the liquefaction plant are likely to be in the form of LNG. The bulk of the equipment volume is likely to contain high pressure natural gas, NGLs or refrigerants.

G.2 LNG receiving terminals

LNG receiving terminals are designed to receive liquefied natural gas from methane carriers, to unload, store this LNG and convert it into the gaseous phase for send out to the gas network or gas consumers.

Thus an LNG receiving terminal provides several essential functions which are:

— unloading;

— storage;

— LNG recovery and pressurizing;

— vaporizing;

— gas quality adjustment.

G.3 LNG peak shaving plants

LNG peak shaving plants, which liquefy natural gas taken from the commercial gas network, are an order of magnitude smaller than export terminals. The quality of the gas feed simplifies the processing requirements compared with an LNG export terminal. Liquid hydrocarbons are likely to be limited to the LNG and refrigerant for which storage is commonly provided. No fractionation facilities are usually required. H_2S may be assumed to be present in commercial natural gas at levels below that requiring specific treatment.

The following refrigeration processes are commonly used in LNG peak shaving plants (for more details see Annex L):

— one mixed refrigerant cycle;

— cascade mixed refrigerant cycle;

— nitrogen expander cycle;

— methane/nitrogen expander cycle;

— open cycle expander.

The turbo-expanders are mostly coupled to booster gas compressors.

Where a large flow of high pressure natural gas is expanded to feed a lower pressure network, the expansion can take place in a turbo-expander to provide the refrigeration needed to liquefy the natural gas. The amount of refrigeration available is directly dependent on the pressure ratio of the expansion but a common production rate is 10 % of the flow of expanded gas.

G.4 LNG satellite plants

An LNG satellite plant is generally a small station where LNG is stored and vaporized for peak shaving purposes or to supply an isolated local distribution network. The LNG is delivered by road or rail tankers or small LNG carriers coming from either an LNG receiving terminal or an LNG peak shaving plant.

The main functions of a LNG satellite plant are the same as the LNG receiving terminal.

G.5 LNG bunkering stations

An LNG bunkering station is generally a site where LNG is received and then stored for bunkering of LNG as fuel for ships either through a piping system, trucks, containers or barges.

A bunkering station would be provided with LNG either from a liquefaction plant (remote or adjacent to the bunkering station) or from a receiving terminal.

Annex H
(informative)

Definition of different types of LNG tanks

H.1 General

The different types of tanks are defined in Clause 6.

The vertical, cylindrical, flat-bottomed steel tanks are described in EN 14620-1.

Other following types could also be considered.

H.2 Spherical storage tank

The spherical, single containment tank system consists of an un-stiffened, sphere supported at the equator by a vertical cylinder. The tank is designed and constructed in compliance with the Gas Carrier Code of the International Maritime Organisation (IMO type B tank, [18]).

The spherical tank geometry allows accurate prediction of structural integrity. It can be designed for high earthquake accelerations.

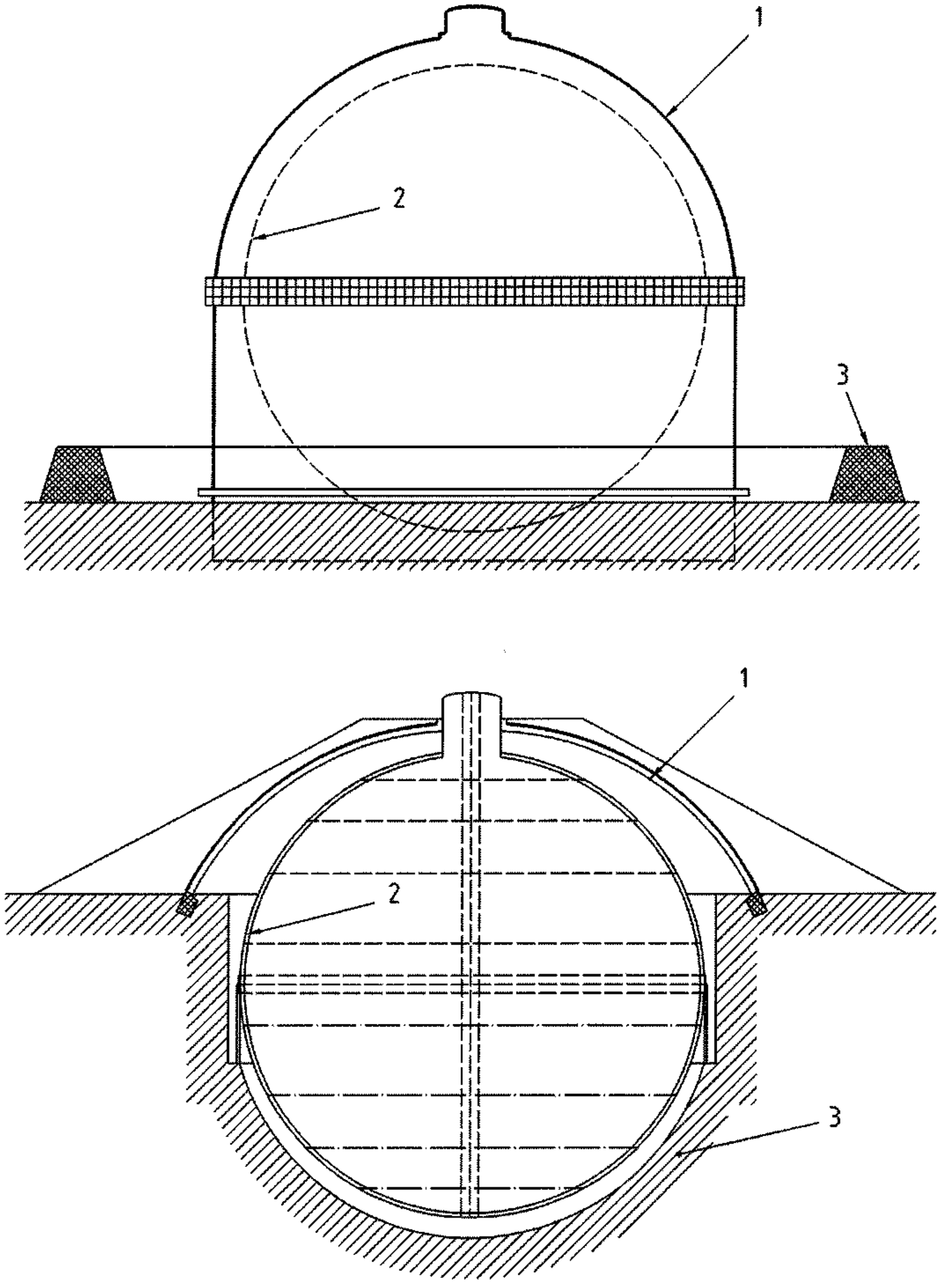
An above-ground spherical tank shall be surrounded by a bund wall (see 6.8.) to contain any leakage.

NOTE Examples of cryogenic spherical tanks are given in Figure H.1.

H.3 Cryogenic concrete tank

For this type of vertical, cylindrical, flat bottom tanks, the walls of the primary and secondary containers are both of pre-stressed concrete.

NOTE Examples of cryogenic concrete tanks are given in Figure H.2.



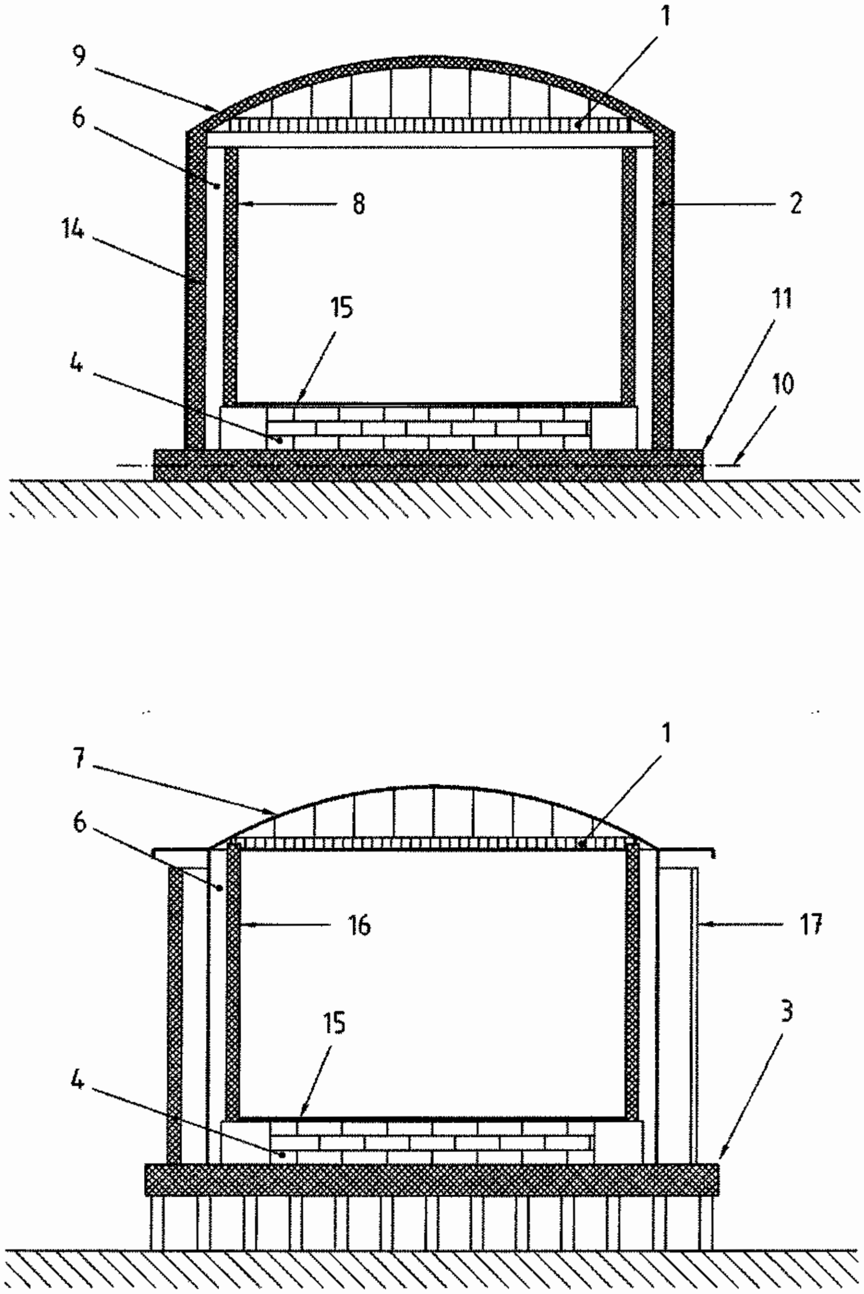
Key

1 outer shell

2 primary container

3 secondary container

Figure H.1 — Examples of spherical storage tanks



Key

1	suspended deck (aluminium deck)	9	reinforced concrete roof
2	pre-stressed concrete secondary container	10	bottom heating
3	elevated slab	11	concrete outer raft
4	base insulation	14	carbon steel liner
6	loose fill insulation	15	9 % Ni steel base
7	outer steel roof	16	cryogenic pre-stressed concrete primary container
8	primary container	17	cryogenic pre-stressed concrete secondary container

Figure H.2 — Examples of cryogenic concrete tanks

Annex I
(informative)

Frequency ranges

Table I.1 — Frequency ranges for hazard assessment

Range 1:	Frequency of occurrence of more than ***once in 10 years.***
Range 2:	Frequency of occurrence in the range between ***once in 10 years and once in 100 years.***
Range 3:	Frequency of occurrence in the range between ***once in 100 years and once in 1 000 years.***
Range 4:	Frequency of occurrence in the range between ***once in 1 000 years and once in 10 000 years.***
Range 5:	Frequency of occurrence in the range between ***once in 10 000 years and once in 100 000 years.***
Range 6:	Frequency of occurrence in the range between ***once in 100 000 years and once in 1 000 000 years.***
Range 7:	Frequency of occurrence of ***less than once in 1 000 000 years*** (i.e. falling of meteorite, etc.)

Annex J
(informative)

Classes of consequence

Classes of consequence take into account the extent of injury for the plant personnel and for the public and equipment damage inside and outside the plant boundaries, but on the only safety and environmental aspects.

Five classes of consequences have been identified on the basis of:

— fatalities;

— accident related to process operation with loss time;

— release of hydrocarbons.

These classes are ranked from 1 to 5 in descending order.

Table J.1 — Classes of consequence for hazard assessment

	Criteria unit	Class 1	Class 2 [a]	Class 3	Class 4	Class 5
Fatalities	Dead persons	More than 10	1 to 10	0	0	0
Accident with loss time	Injured persons	More than 100	11 to 100	2 to 10	1	0
Release of hydrocarbons	Tons	More than 100	10,01 to 100	1,01 to 10	0,1 to 1	Less than 0,1

[a] The class is close to SEVESO Directive criteria [Council Directive 96/82/EC of 9 December 1996 on the control of major-accident hazards involving dangerous substances].

Annex K
(informative)

Levels of risk

K.1 General

Three categories of risk may be used:

— Level 3: situation which is undesirable and cannot be tolerated. Remedial action required (Not Acceptable);

— Level 2: situation which shall be improved. A level at which it shall be demonstrated that the risk is made As Low As Reasonably Practical (ALARP);

— Level 1: normal situation (Acceptable).

K.2 Acceptability criteria

Tables K.1 and K.2 give examples of risk acceptability criteria matrixes for the cumulative total of all plant risks and so can only be used when all hazards have been assessed within the risk assessment. It cannot be used to assess individual hazard sequences unless each hazard is allotted a proportion of the allowable overall plant risk. Should the overall risk level be exceeded a choice of which hazards to improve can be made so that the overall risk level is improved in the most cost effective manner.

The acceptability criteria are more stringent for the consequences outside the plant boundaries.

Table K.1 — Determination of level of risk inside plant boundary

Risk		**Consequences class**	**Consequences Class**	**Consequences Class**	**Consequences Class**	**Consequences Class**
Frequency for all plant accidents	Cumulative frequency (per year)	5	4	3	2	1
Range 1	> 0,1	2	2	3	3	3
Range 2	0,1 to 0,01	1	2	2	3	3
Range 3	0,01 to 0,001	1	1	2	2	3
Range 4	0,001 to 10^{-4}	1	1	1	2	2
Range 5	10^{-4} to 10^{-5}	1	1	1	1	2
Range 6	10^{-5} to 10^{-6}	1	1	1	1	1
Range 7	< 10^{-6}	1	1	1	1	1
TOLERABILITY OF HAZARDS: 1 = normal situation 2 = ALARP region 3 = not acceptable						

Table K.2 — Determination of level of risk outside the boundary plant

Risk		**Consequences class**	**Consequences Class**	**Consequences Class**	**Consequences Class**	**Consequences Class**
Frequency for all plant accidents	Cumulative frequency (per year)	5	4	3	2	1
Range 1	> 0,1	2	3	3	3	3
Range 2	0,1 to 0,01	2	2	3	3	3
Range 3	0,01 to 0,001	1	2	2	3	3
Range 4	0,001 to 10^{-4}	1	1	2	2	3
Range 5	10^{-4} to 10^{-5}	1	1	1	2	2
Range 6	10^{-5} to 10^{-6}	1	1	1	1	2
Range 7	< 10^{-6}	1	1	1	1	1
TOLERABILITY OF HAZARDS: 1 = normal situation 2 = ALARP region 3 = not acceptable						

Annex L
(informative)

Typical process steps of liquefaction

L.1 Introduction

Liquefaction plant is considered to start at the inlet to the acid gas removal unit and to terminate at the inlet to the LNG (and other liquid hydrocarbon) rundown lines. Gas transmission, treatment upstream of acid gas removal and product and refrigerant storage are excluded from this annex. Descriptions of commonly used processes are given, however there is no implication that these are the best or only processing options.

L.2 Treatment of natural gas/extraction of acid gases

L.2.1 General

The purpose of the acid gas extraction unit is to reduce the CO_2 and H_2S content within the gas to be liquefied to values which are compatible with commercial and legal gas specifications and are compatible with cooling requirements (risk of solidification). Contents tolerated within the treated gas are:

$CO_2 < 100 \times 10^{-6}$ *by volume*;

$H_2S < 4 \times 10^{-6}$ *by volume*.

The selection of the treatment process will depend on the type and concentration of impurities to be removed. Commonly used processes are described below.

L.2.2 Absorption processes

L.2.2.1 Principle of operation

The principle of such processes is to absorb acid gases from the gas to be treated, by scrubbing with an absorption solution within a tray-type or packed-type absorber.

The absorbent solution can be:

— either chemical (formation of a chemical compound which, on temperature rise, dissociates by releasing acid gases);

— or physical (absorption brought about by pressure, which then, through lowering of pressure, allows the initial solution to be regenerated).

In certain processes, the absorption solution is a mixture of chemical and physical solvents.

Some absorption solutions contain additives designed to improve reactivity of the solvent, reduce risks of corrosion or prevent foaming.

L.2.2.2 Operating parameters/performance data

Design of an acid gas extraction plant requires knowledge of nominal values of the operating parameters of the plant which are listed below, and also the ranges of variation of such parameters:

- flow rate, pressure, temperature, composition and acid gas content of incoming natural gas entering the plant for treatment;
- flow rate, pressure and acid gas content of treated natural gas leaving the plant;
- absorption solution circulation rate and concentration.

In particular, the following values should be ensured by the process holder and/or the manufacturer:

- flow rate of treated natural gas leaving the plant;
- acid gas content of outgoing treated natural gas;
- pressure drop on the natural gas circuit;
- absorption solution concentration;
- absorption solution circulation rate;
- absorption solution losses;
- consumption of utilities, for the rated operating conditions of the plant.

L.2.2.3 Particular features

Design of the plant should take account of certain features which are specific to this type of plant.

a) Risks of foaming in the absorber

Formation of foam inside the absorber brings about deterioration in the performance of the absorber and driving of foam (and therefore of absorption solution) with the treated gas as it leaves the over head of the absorber.

Foaming can occur for several reasons:

1) incorrect design or poor sizing of the absorber;

2) presence of solid particles in the solution;

3) presence of liquid hydrocarbons in the scrubbing solution.

The absorption solution should be filtered in order to prevent accumulation of solid particles.

The gas entering the absorber should not contain liquid hydrocarbons. It should furthermore be checked that there is no risk of condensation of hydrocarbons within the absorber. If the presence of liquid hydrocarbons in the absorption solution cannot be excluded, installation of a device for absorption of liquid hydrocarbons (passing at least part of the solution in circulation over a bed of activated carbon, for example) is recommended.

"Anti-foam" additive can be injected into the solution as long as its presence will not bring about secondary effects which impair operation of the plant.

b) **Risks of corrosion**

Under certain circumstances (such as high temperature or high acid gas concentration) absorption solutions can become corrosive to steel.

In addition to weakening of the metal, corrosion residue promotes foaming in the absorber - hence the importance of proper selection of construction materials and heat treatment in order to prevent corrosion phenomena.

A corrosion inhibitor can be added to the solution as long as it does not bring about secondary effects which are harmful to operation of the plant.

L.2.3 Molecular sieve adsorption process

Molecular sieves, which are widely used for gas dehydration, have the property of adsorbing acid gases as well. However, the number of molecular sieve vessels to be installed, and the volume of flow of regeneration gas necessary, limit use of molecular sieves to natural gases with low acid gases content (less than 0,2 % by volume for large capacity LNG plants up to about 1,5 % by volume for LNG peak-shaving plants).

Please see information on dehydration units in L.3 below for use of a process of this type.

L.2.4 Other sulphur processes than H_2S

In addition to H_2S, the raw natural gas can contain other sulphur compounds (COS, mercaptans etc.) which are generally not removed by the acid gas removal treatment, while LNG specifications usually include a limit on total sulphur quantity. The concentration of such sulphur compounds in the natural gas can therefore need to be reduced.

The choice of process is related to the quantity and type of sulphur compounds present in the raw natural gas stream. Possible processes include cryogenic distillation (the sulphur compounds are removed during NGL extraction from the natural gas and definitively removed by treatment of the LPG) and on the molecular sieves used for dehydration.

L.3 Natural gas treatment/dehydration

L.3.1 General

The water content of treated gas should be less than 1×10^{-6} by volume. Dehydration of natural gas to be liquefied is generally carried out on molecular sieves. Activated alumina or silica gel can also be used.

L.3.2 Principle of operation

Dehydration is done by passing wet natural gas over a bed of molecular sieves. Molecular sieves are aluminosilicates of sodium, calcium or potassium with regular pore size crystalline structures which allow great selectivity concerning the size of molecules adsorbed and give high adsorption capacity.

A dehydration unit includes at least two dryers which contain molecular sieves. One is in adsorption while the other is in regeneration. Regeneration is carried out at high temperature (200 °C to 250 °C) by circulating dry gas which has been heated beforehand in a heater or a heat exchanger.

Regeneration can be carried out either at the same pressure as adsorption, using dry gas recycled through a compressor, or at low pressure.

In order to reduce the quantity of water to be removed from the gas by the molecular sieves, natural gas is generally cooled - while at the same time remaining above hydrate formation temperature - in such a way as to condense part of the water before passing over the molecular sieves.

L.3.3 Operating parameters/performance data

Design of a dehydration plant requires knowledge of nominal values of the operating parameters of the plant which are listed below, and also the ranges of variation of such parameters:

— flow rate, pressure, temperature, composition and water content of incoming natural gas entering the plant for dehydration;

— flow rate, pressure and water content of dry natural gas leaving the plant;

— flow rate and pressure of regeneration gas to the dryers;

— temperature of hot regeneration gas;

— duration of cycle.

In particular, the following values should be ensured by the process holder and/or the manufacturer, for the rated conditions of operation of the plant:

— flow rate of dry natural gas leaving the plant;

— pressure drop on the natural gas circuit;

— water content of outgoing dry natural gas;

— flow of regeneration gas to dryers;

— temperature of hot regeneration gas;

— life of molecular sieves.

L.3.4 Particular features

In order not to damage the crystalline structures of molecular sieves, it is necessary to protect them against any untimely arrival of liquid (acid gas removal solution, water or liquid hydrocarbons).

Attrition, which causes formation of molecular sieve dust can be minimized through careful control of the changes in regeneration gas temperature and, when regeneration is carried out at low pressure, by gradual de-pressurizing and re-pressurization.

Low points on pipe works where water could condense and then accumulate should be avoided.

The presence of molecular sieve dust can upset operation of valves and, therefore, it is necessary to take account of this when choosing the type of valve and positioning of valves.

Dry gas leaving the dryers should be carefully filtered (cartridge filters, generally) in order to prevent any entrainment of molecular sieve dust into the cryogenic exchangers of the liquefaction unit.

It is recommended to provide a standby period at the end of the regeneration phase of approximately 15 min to 30 min for export terminals and up to 10 min for peak-shaving plants. This period of time makes it possible for action to be taken in the event of mal-operation of automatic mechanisms or blockage of a valve.

L.4Treatment of natural gas/removal of mercury

Certain natural gases can contain quantities of mercury. Mercury can, under certain conditions, be extremely corrosive to aluminium which is a metal widely used for construction of cryogenic exchangers and possibly certain other items of equipment. If the gas to be liquefied contains mercury, it is essential to remove it before the natural gas enters the liquefaction unit.

Extraction of mercury from natural gas is done by passing the gas through a reactor bed made up of sulphur, iodine or metal sulphide impregnated beads or pellets of high porosity alumina, activated carbon or molecular sieve. In general, the target specification at the outlet of the de-mercurization unit shall be below 0,01 µg/m³ of mercury of gas measured at 1 013 mbar and at 0 °C.

This process is not regenerative. The absorbent mass should be replaced when it is saturated.

L.5Natural gas liquefaction unit

L.5.1 General

The purpose of a liquefaction unit is to transform treated natural gas into liquefied natural gas (LNG) at its boiling temperature at atmospheric pressure, in order to permit its storage and transportation.

L.5.2 Principle of operation

L.5.2.1 Natural gas circuit and fractionation

Treated gas enters the liquefaction unit after acid gases, water and, if appropriate, mercury have been extracted. At this stage, however, the gas can still contain heavy and aromatic hydrocarbons. If not removed these components are liable to solidify in the course of cooling, gradually clogging the cryogenic exchangers and potentially relief valves. The natural gas is therefore cooled from ambient to LNG temperatures in two stages, generally designated as pre-cooling and liquefaction.

After pre-cooling the partially condensed natural gas is fractionated in such a way as to extract a C_2+ *cut*. This C_2+ *cut* contains all the undesirable (C_5+) heavy hydrocarbons, and also ethane, propane and butane. A small part of these components might be used as make-up for refrigerant cycles, and surpluses might be extracted for marketing or re-injected into the natural gas to be liquefied. The higher the desired extraction rate is for ethane, propane and butane, the lower the temperature will be at which fractionation is to be carried out. If sulphur species such as mercaptans are removed at this stage, this can dictate the process conditions for fractionation.

Natural gas thus cleaned of its heavier hydrocarbons can then be liquefied. The higher is the pressure of the natural gas, the smaller is the work necessary for liquefaction. Therefore every effort should be made to operate at the maximum pressure compatible with the heavy hydrocarbon extraction.

Following condensation at high pressure, the liquefied natural gas shall be sub-cooled to avoid excessive vaporization following expansion to the atmospheric pressure of the storage tanks. Two approaches are possible:

— if the natural gas does not contain much nitrogen (less than 1,5 mole % in general), carry out complete sub-cooling of the LNG down to an enthalpy level equivalent to a temperature slightly below the bubble point temperature (approximately – 160 °C) at atmospheric pressure. The sub cooled LNG can then be sent directly to the storage tanks;

— carry out partial sub-cooling (approximately – 150 °C) followed by expansion in a flash drum at a pressure which is slightly above atmospheric; the flash gas produced on expansion is re-compressed, in general for supplying the fuel gas system, whereas the LNG contained in the flash drum is sent to the tanks using a pump. In LNG peak-shaving plants, the final flash can be done directly in the vapour space of the tank.

Complete sub-cooling requires additional liquefaction energy consumption but avoids the need for LNG pumps and a flash gas compressor. If nitrogen needs to be removed to obtain the desired LNG quality this operation is done in the final flash, or, for high nitrogen contents, in a low temperature fractionating column.

L.5.2.2 Refrigeration cycles

The purpose of the refrigeration cycle(s) is to extract sensible and latent heat from the natural gas to transform it from the gaseous state at high pressure to the liquid state at atmospheric pressure.

Liquefaction of natural gas requires production of refrigerating power from ambient temperature to approximately – 150 °C to – 160 °C.

Base-load liquefaction plants generally use two refrigeration cycles working in cascade, whereas only one refrigeration cycle is generally preferred in LNG peak-shaving plants.

A refrigerant compressor can be driven by gas turbine, steam turbine or electric motor. Refrigerants are made up either of a mixture of light hydrocarbons (with, if appropriate, nitrogen in order to obtain the lowest temperatures), or by a pure substance such as propane, for example.

L.5.3 Operating parameters/performance data

Design of a natural gas liquefaction unit requires knowledge of nominal values of the operating parameters of the unit which are listed below, and also the ranges of variation of such parameters:

— flow rate, temperature and the detailed composition of the natural gas entering the unit;

— flow rate of liquefied natural gas leaving the unit;

— pressure, temperature and composition of outgoing LNG;

— conditions: temperature, pressure, flow rate and composition of other streams leaving the unit (C_5+ cut, ethane, propane, butane, gasoline and flash gas if appropriate);

— conditions of the different utilities available and, most especially, temperature of the cooling air or water;

— extraction rates of commercial ethane, propane and butane.

In particular, the following values should be guaranteed by the process licenser and/or the manufacturer, for the rated operating conditions of the plant:

— the flow rate of LNG leaving the unit;

— the temperature of the outgoing LNG;

— the composition of the outgoing LNG;

— the flow rate, pressure, temperature and composition of commercial ethane, propane and butane, as appropriate;

— utility consumptions.

L.5.4 Low temperatures

The fact of working at low temperature, on the one hand, and of having units which are often of very high capacity, on the other, leads to characteristics which are specific to this type of plant.

Design temperatures of equipment and of pipe-work require the selected construction materials to be compatible with the temperatures encountered in both normal and transient operation (start-up, shutdown, upset) of the unit.

Three categories of steel materials are generally provided for (see EN ISO 16903 for details):

— carbon steel for non cryogenic low temperatures (typically > −46 °C);

— 3,5 % nickel alloy steel for design temperatures > −104 °C;

— 9 % nickel alloy steel or stainless steel for design temperatures > −196 °C.

These categories can eventually be extended where the design temperature can only be obtained by depressurization and where steps are taken to avoid re-pressurization of cold equipment.

As in any low temperature plant, it is necessary to install means for careful drying of circuits prior to starting in order to eliminate any trace of moisture in the cryogenic circuits as a whole.

Make-up for coolants should be perfectly dry and shall not contain any component liable to solidify at the temperatures encountered.

L.5.5 Specific equipment

L.5.5.1 General

Natural gas liquefaction units contain specific items of equipment, cryogenic exchangers, turbo-compression sets and cooling systems, which are particularly large in LNG export terminals.

L.5.5.2 Cryogenic exchangers

The design of cryogenic exchangers of LNG units should comply with a number of requirements:

— presence of several warm side fluids (refrigerants at various pressure stages, vapour and/or liquid, natural gas) flowing counter current (and/or cross current) to lower pressure refrigerants which are generally bi-phase;

— large temperature differences for each fluid across the heat exchanger;

— small temperature differences between the warm and the cold circuits throughout the heat exchanger;

— significant metal temperature gradients within the heat exchanger;

— low temperatures;

— very large amounts of heat exchanged;

— high differential pressures;

— high mass flow rates.

Two types of equipment enable the requirements as a whole to be met: spool-wound heat exchangers and plate-fin heat exchangers.

Spool-wound heat exchangers are widely used in large capacity LNG plants. They are made up of a succession of layers of aluminium (or stainless steel) tubes helically wound around a core. Fluids at high pressure to be condensed or sub-cooled circulate inside the tubes, whereas the coolant is vaporized at low pressure in the shell outside the tubes. Such a design allows exchangers with very large unit heat transfer areas to be built.

Aluminium brazed plate fin exchangers are widely used in the cryogenic field for gas separation and/or gas liquefaction.

The design of these exchangers results in a large heat transfer area within the relatively small volume of a core.

Brazed plate fin heat exchangers are manufactured as modular cores of up to a maximum size of approximately 12 m^3. For high pressure service, the maximum core size should be further limited to ensure the mechanical integrity of the heat exchanger. Large heat transfer duties need therefore to be achieved by the assembly of several cores in parallel, usually in perlite filled cold boxes.

Other plate-type heat exchangers, using welded stainless steel plates, presently used in hot services, could be adapted to cryogenic services in LNG units.

L.5.5.3 Compression systems

L.5.5.3.1 General

LNG export terminals require the use of very powerful refrigerant compression systems.

L.5.5.3.2 Refrigerant compressors

Centrifugal compressors are the type most widely used in the LNG industry. However the quest for increased LNG export terminal unit capacity has led to the increased use of axial type compressors when the compressor suction flow exceeds centrifugal compressor capacity. Furthermore, axial compressors have a better efficiency than centrifugal machines.

Careful design and manufacture of compressor anti-surge devices is required. Indeed, the power dissipated in such devices is so high that aero-elasticity and excessive stress can arise leading to metal cracks and ruptures if not properly taken into account.

L.5.5.3.3 Drivers

Many existing LNG export terminals use steam-turbines as refrigeration compressor drivers. Steam turbines are available in a very large power range and have excellent reliability.

Gas turbines are increasingly preferred as refrigeration compressor drivers resulting from several technical factors:

— no high pressure steam is required (with the corresponding boiler feed water treatment);

— large reduction of cooling water consumption;

— it is possible to increase the overall efficiency by heat recovery on the gas turbine exhaust gases.

The influence of ambient air temperature variations on the power delivered by the gas turbine (power decreases when air temperature increases) needs to be taken into account.

Two-shaft gas turbines are commonly used as compressor drivers because of the advantages of operating at variable speed.

If the power requirement exceeds the capability of two-shaft gas turbines, it is possible to use large single shaft gas turbines originally built for electrical power generation and where operation at constant speed is no handicap. Adjustment of the composition of the refrigerant mixture during design and if required during operation can be made to fit the constant compressor speed. Start-up requires special attention.

In all cases, because of the importance of the refrigerant compression systems for the good operation of LNG units, such equipment should be designed, manufactured, operated and maintained very carefully in order to achieve maximum reliability.

L.5.5.4 Cooling system

In base load liquefaction trains, a huge heat duty shall be rejected to the environment via the cooling system.

As such plants are most frequently located on the coast for transportation of LNG by tanker; sea water is frequently used as the cooling medium.

The volume flow of sea water necessary, particularly when refrigerant compressors are driven by steam turbines, can justify the choice of a siphoned sea water system which permits a significant reduction in pumping energy and reduces the risks of corrosion, by lowering the oxygen content in the cooling system. In a sea water circuit particular attention should be paid to corrosion and to the risk of development of living organisms (algae, mussels, etc.) within the circuit.

If site conditions (such as elevation or sea water quality) make it uneconomic to use sea water as a cooling fluid, it is possible to use either a closed fresh water circuit with cooling tower or air-cooled heat exchangers. Problems can arise because of development of bacteria in fresh water circuits. This should be prevented by appropriate water treatment.

Annex M
(informative)

Odourant systems

M.1 Odourants in general

Odourization is achieved by the addition of an odourant which is typically a blend of volatile organic sulphur compounds e.g. ethyl mercaptan, tertiary butyl mercaptan, methyl ethyl sulphide and diethyl sulphide, or a single component such as tetrahydrothiophene. Odourant liquids are volatile, flammable and of extremely noxious smell.

In their concentrated form most of those products are toxic.

M.2 Odourant systems requirements

M.2.1 General

The odorizing plant generally consists of a storage tank, smaller feed tanks, pumps and associated valves and pipe-work. The plant should be designed for ease of maintenance and operation and protection from possible impact damage. Care should be taken that materials used in the construction are compatible with odourant. In particular, copper and copper based alloys, polyethylene and polypropylene and butyl and natural rubber are attacked by liquid odourants and should not be used in the construction of this equipment. Welded pipe connections should be used whenever possible.

During normal operations there should be no emission of odourant to the atmosphere and the system shall be designed to eliminate and minimize all possible emissions.

The tanks and injection equipment should be located within a bunded area with provision for the drainage of rainwater. It should not be possible for spills or leaks to accumulate under storage vessels or equipment.

M.2.2 Storage

Liquid odourant may be stored in fixed tanks with a road tanker off-loading point, or supplied in stainless steel transportable containers with international approval for the transport of dangerous goods under UN 1A1W/X2.0/900. This latter method enables connection directly to injection equipment with dry break couplings, and flexible braided PTFE hoses, thereby avoiding the need to transfer odourant from a road tanker to the fixed storage tank and reducing the risk of accidental spillage.

It is recommended that there should be the minimum number of pipe connections to the storage tank below the maximum liquid content level of the tank.

An oxygen free gas blanket compatible with the selected odourant should be provided above the liquid odourant.

M.2.3 Odourant pumps and valves

It is recommended to use pumped odourant plant to odorize large volumes of gas. Where volumes of gas to be odorized are small, the use of an evaporative type of odourant plant can be considered.

Odourant pumps should be of a design, which minimizes the possibility of leakage.

Pumps should have filters on the suction side and be capable of handling the whole range of flows.

Piping should be seamless stainless steel and connections, wherever possible, should be welded.

All valves, flanges and fittings should be designed in accordance with EN 1092-1, EN 1759-1, EN 1514 and EN 12560.

M.3 Odourant handling

M.3.1 General

The precautions for odourant handling are those of any low flash point material. Additionally, owing to its pungency and toxicity see M.6 safety of personnel.

M.3.2 Delivery

Inert gas and methanol should be available to flush and purge the delivery hose and associated equipment if bulk transfer is to be undertaken.

Spillage trays, absorbent and decontamination equipment should be available at the tanker-unloading bay.

Self-sealing couplings should be used on the connections from the delivery vehicle, designed to close when the hose is disconnected.

The tanker should be connected to a static earthing point, temporarily, to discharge any accumulated electrical charge. The delivery hose should be electrically bonded to the bulk storage tank.

A vapour return system between delivery and storage tanks should normally be used for bulk transfer. If not a flare system or other means of disposal such as connection to the boil-off system can be considered.

M.3.3 Flushing and purging

All equipment should be decontaminated prior to dismantling for maintenance or inspection by draining or pumping liquid odourant from the equipment then flushing with methanol or other appropriate medium. After pumping the residual methanol/odourant, vapour can be purged with natural gas and finally inert gas to flare or into a suitable low-pressure line such as the boil-off system. Work should be covered by specially prepared procedures.

M.4 Odourant injection

The facility should be designed to be operable throughout the range of natural gas pressures, which can be seen at the injection point. Spraying nozzles should be sized to suit the full range of gas flow rate; if needed, several nozzles can be installed with appropriate automatic control to maintain a constant ratio of odourant to gas.

The injection stream itself should contain at least two pumps in parallel, one operational and the other standby (depending on the flow range required, a number of differently sized pumps may be used).

The injection rate should be closely monitored and controlled to ensure the minimum degree of odourization is always achieved. It is recommended that the injection rate should be controlled by the signal from the gas flow meters.

The amount of odourant in the gas, if required, can be measured as follows:

— by automatic sulphur titration which continuously measures the total sulphur of a flowing sample of the odorized gas;

— by checks of the odorized gas using a sulphur chromatograph.

M.5 Odourant leakage

A spill or leak of gas odourant results in an obnoxious odour, which - unless promptly neutralized - usually leads to employee and neighbour complaints. It is important that, if spills or leaks occur, the odourants are promptly neutralized and the odour masked. There are several agents available for this and proven methods for effectively handling the situation (see the Material Safety Data-Sheets for advice on clean up).

An effective method of neutralization is based on converting the spilled odourant to a relatively low odour disulphide, through chemical oxidation. This may be achieved by spraying or flooding the spill area with a dilute bleach solution. Either sodium hypochlorite or calcium hypochlorite in dilute solution in water may be used. Dilute solutions are more effective than commercial or concentrated solution; for example, fifty litres of a ½ % solution is generally much more effective than 5 l of a 5 % solution.

Because the chemical oxidation is not instantaneous, it is recommended that an odour-masking agent be applied along with the dilute bleach solution.

Use of dry calcium hypochlorite powder on a concentrated odourant should be avoided because the heat of the exothermic reaction may cause ignition of the organic mercaptan in the odourant.

Spilled liquid should be absorbed using dry sand or other recommended inert absorbent, neutralized and placed in sealed drums for proper disposal. A spillage of liquid odourant can also be blanketed with firefighting foam in order to reduce the evaporation rate.

It should be noted that the precise source of leakage could be difficult to identify as the highly volatile nature of odourant can result in rapid evaporation leaving no visible signs. Odourants have an "odour platform", whereby the concentration in air can increase significantly without any noticeable increase in smell.

M.6 Safety of personnel

The Material Safety Data-Sheets for the odourant should be consulted for advice on the personal protection equipment required for the operators to safely handle the material. As a minimum, in any operation involving odourant, operators shall wear PVC gloves, eye protection and impervious clothing, which is readily decontaminated after use.

If a spillage of odourant occurs, personnel required to work in the area should wear self-contained breathing apparatus together with the above protective clothing.

If an operator is splashed with odourant, any contaminated clothing should be removed and skin washed with running water. A doctor should examine all eye splashes.

Safety shower and eyewash should be installed in the vicinity of the odourant handling area.

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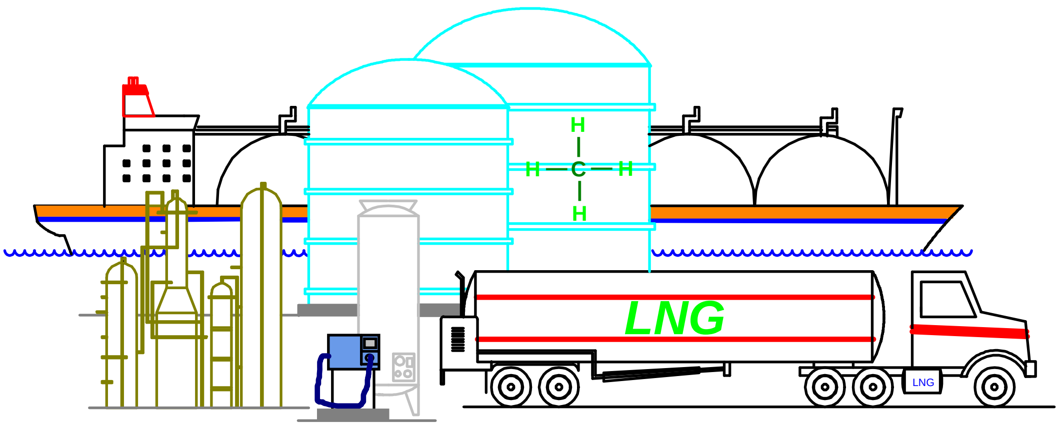

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Safety History of International LNG Operations

INTRODUCTION:

LNG (Liquefied Natural Gas) has been a viable form of energy and safely handled for many years. The industry is not without its incidents and accidents, but it maintains an enviable "modern-day"[1] safety record. The process of natural gas liquefaction, storage and vaporization is not a new technology. Earliest patents involving cryogenic liquids date back into the mid-1800s. The first patent directly for LNG was awarded in 1914. In 1939, the first commercial LNG peak-shaving plant was built in West Virginia. There are now over 120 peakshaving and LNG storage facilities[2] worldwide, some operating since the mid-1960s. In addition, there are 58 import (regasification) terminals worldwide and More than 23 base-load liquefaction (LNG export) facilities in various countries including Abu Dhabi, Algeria, Angola, Australia, Brunei, Egypt, Equatorial Guinea, Indonesia, Iran (2012), Libya, Malaysia, Nigeria, Norway, Oman, PNG (2013), Qatar, Russia, Trinidad, Yemen and U.S. (Alaska) currently in operation. LNG is transported by a fleet of more than 300 LNG Carriers of varying sizes from 18,500 M^3 (cubic meter) to 265,000 M^3. This fleet of LNG ships delivers to receiving terminals in countries including: Argentina, Belgium, Brazil, Canada, China, Dominican Republic, France, Greece, India, Italy, Japan, Korea, Kuwait, Mexico, Portugal, Spain, Taiwan, Turkey, the U.K. and, of course, the U.S., including Puerto Rico.

The LNG storage tanks at these facilities are typically constructed of an interior cryogenic container, usually made of 9% nickel steel, stainless steel, aluminum or other cryogenic alloy. The outside wall is usually made of carbon steel or reinforced concrete. A thick layer of an insulating material such as Perlite or cellular glass block separates the two walls.

For land-based facilities, single containment tank designs have a secondary earthen or concrete containment having a minimum capacity exceeding the capacity of the LNG tank(s) surrounds the LNG tank(s). When a tall concrete wall having an internal diameter slightly greater than the outside wall of the LNG tank, is used, this is known as a double containment design for the LNG tank. When the outer tank wall and roof are of reinforced concrete then the tank is considered to be a full containment type. In other designs, the tanks are buried below ground level or for smaller storage volumes are vacuum jacketed bullet type pressure vessels located above ground. In all cases, the objective is to minimize the risks and exposure of the public associated with failure of the LNG primary containment based on a *catastrophic tank failure*[3] scenario. Many newer tanks are equipped with top tank penetrations only, i.e., no bottom or side wall penetrations, thus, even in the unlikely event of an external piping failure, tank contents remain in place.

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1 *Modern Day* – Post mid-1950s - Cryogenic technologies came of age during the late 1950s and early 1960s with the development of the U.S. space program where cryogenic fuels such as liquid hydrogen and liquid oxygen had to be routinely and safely handled.

2 This does not include dozens of small LNG vehicle fueling stations and industrial LNG fuel facilities.

3 There has never been a *catastrophic tank failure* with any LNG, or similarly designed, storage tank fabricated of the proper cryogenic alloys.

Safety History of International LNG Operations

With a few exceptions, LNG handling facilities have accumulated an exceptionally superior safety record when compared to refineries and other petrochemical industries. With the exception of the 1944 "Cleveland Disaster," all LNG-related injuries and/or fatalities, however devastating, have been limited to plant or contractor personnel. There have been no LNG shipboard LNG related deaths. There has not been a member of the public injured by an incident involving LNG since the failure of the improperly designed/constructed Cleveland facility. Small LNG vapor releases and minor fires have also been reported, but impact was limited to the plant and the hazard was promptly handled by plant personnel. Other accidents have occurred during the construction and repair of LNG facilities. Some of these accidents have been used to tarnish the exceptional safety record of LNG, but as no LNG was directly involved in the incident, these accidents can only truly be called "construction" accidents. Damage has always been limited to the plant proper.

The following three sections discuss land-based, LNG ship and over-the-road LNG transport incidents respectively. Each section references an appendix listing the various incidents.

SAFETY RECORD OF LAND-BASED LNG FACILITIES

The first commercial facility for producing or utilizing LNG was a peakshaving plant[4] that began operations in 1941 in Cleveland, Ohio. Since then, more than 150 other peakshaving plants have been constructed worldwide (approximately one-half of these are satellite facilities that have no liquefaction capability). In addition, large base load natural gas liquefaction plants (export facilities) and More than 30 large LNG import terminals have been constructed.

There have been five incidents in operating LNG facilities directly attributable to the LNG process that resulted in one or more fatalities – Skikda, Algeria – 2004; P. T. Badak (Bontang, Indonesia), 1983; Cove Point Maryland, 1979; Arzew, Algeria, 1977; and Cleveland, Ohio, 1944. There were two other "LNG" incidents (Portland 1968 and Staten Island 1973) involving worker deaths, but these correctly should be classified as "construction accidents" as no LNG was present. See Appendix A for more details on these incidents and a complete listing of land-based LNG facility incidents.

The accident at East Ohio Gas Company's peakshaving plant in Cleveland, Ohio, is the only incident that involved injuries or fatalities to persons not employed by the LNG facility or by one of its contractors. This accident is often used as an example of the danger or risk involved in the LNG industry. However, the LNG industry has changed dramatically since 1944, as has virtually every other technology. Modern LNG plants are designed and constructed in accordance with strict codes and

[4] A peakshaving plant liquefies natural gas when customer demand for gas is low and then vaporizes the LNG when demand is high, thus handling periods of peak demand that cannot be met by existing gas pipelines.

standards that would not have been met by the Cleveland plant. For example, the alloy used in Cleveland for the inner vessel of the LNG storage tank is now forbidden for use at LNG temperatures and each LNG tank must now be located within a dike capable of containing at least 110% of the tank's capacity. Further, the National Association of State Fire Marshals concluded in their May 2005 report,[5] "*Had the Cleveland tank been built to current codes, this accident would not have happened*."

Although Appendix A is intended to be a comprehensive listing of incidents that have occurred in land-based LNG facilities; it does not include all of the minor, but reportable incidents. For example, the outer roofs or domes of a few conventional double-wall LNG tanks have suffered small cracks as a result of low temperature embrittlement initiated by leaks of LNG from over-the-top piping. These cracks allowed LNG vapor (i.e., natural gas) to escape from the tanks. In each case, the tanks were safely repaired without being taken out of service. Similarly, the inner tanks of several conventional LNG storage tanks (i.e., cryogenic metal inner tank and carbon steel outer tank) have been cracked as a result of frost heave brought on by inadequate or inoperative below-tank heaters. These tanks have been safely entered, repaired and put back into service.

SAFETY RECORD OF LNG SHIPS (ALSO KNOWN AS LNG CARRIERS)

The first transportation of LNG by ship took place early in 1959 when the *Methane Pioneer* (an ex-Liberty ship that had been extensively modified) carried 5,000 M^3 (cubic meters) of LNG from Lake Charles, Louisiana, to Canvey Island, near London, England. Commercial transportation of LNG by ship began in 1964 when LNG was transported from Arzew, Algeria to Canvey Island in two purpose-built ships—the *Methane Princess* and the *Methane Progress*.

The overall safety record compiled by LNG ships during the forty six-year period 1964 - 2010 has been remarkably good. During this period, the LNG Carrier ship fleet has delivered more than 30,000 shiploads of LNG, and traveled more than 100 million miles while loaded (and a similar distance on return ballast voyages).

In all of these voyages and associated cargo transfer operations (loading/unloading), no fatality has ever been recorded for a member of any LNG ship's crew or member of the general public as a result of hazardous incidents in which the LNG was involved. In fact, there is no record of any fire occurring on the deck or in the cargo hold or cargo tanks of any operating LNG ship.

According to the US Department of Energy, over the life of the industry, eight marine incidents worldwide have resulted in spillage of LNG with some hulls damaged due to cold fracture, but no cargo fires have occurred. Seven incidents not involving spillage were recorded, two from groundings and several ship collisions but with no significant cargo loss.

[5] "Liquefied Natural Gas: An Overview of the LNG Industry for Fire Marshals and Emergency Responders"

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Among LNG import and export terminal personnel, only one death can be even remotely linked to the loading or unloading of LNG ships. (In 1977, a worker in the LNG Export Facility at Arzew, Algeria was killed during a ship-loading operation when a large-diameter valve ruptured and the worker was sprayed with LNG. His death was the result of contact with the very cold LNG liquid; the spilled LNG did not ignite. (See Item 6 in Appendix A.)

Appendix B summarizes the historical record of LNG ship incidents. Although a major effort was made to ensure the record presented is complete, it is possible that some incidents have been missed. However, it is very unlikely that a major incident has been omitted. Firstly, nearly every shipping incident that results in an insurance claim will be published in "Lloyd's List." Secondly, even if the ship owners are self-insured, news of major incidents travels quickly through the LNG industry because it is composed of a relatively small number of ship and terminal operators that often share experiences through industry associations such as SIGTTO (the Society of International Gas Tanker and Terminal Operators).

Also included at the end of Appendix B is a description of a marine incident involving a liquid petroleum gas (LPG) tanker which is of similar design to many LNG ships. The incident provides some insight into the integrity of the product storage systems on these ships.

Over-the Road LNG Transport Accidents

Appendix C provides a partial compilation of over-the-road trucking incidents. It is not intended to be comprehensive as reports of these incidents are maintained in different ways from state to state and internationally. However, much as with LNG ships, it is very unlikely that a major incident has been omitted. The lists do provide examples of the wide range of potential vehicle accidents that can occur. Most notable, not a single person outside the driver of the transport was seriously injured and rarely did product spill and far more rarely did it ignite. It is also important to note that many incidents reported by the media to involve LNG are often, in fact, LPG that is a different product and not at cryogenic temperatures.

Summary

The various incidents discussed, when taken on a case-by-case basis, attests to LNG's safety record. The fact that most LNG opponents cite Cleveland and Staten Island as examples of the dangers of LNG, clearly indicate that there is little else to make their point. As devastating as both Cleveland and Staten Island were, they have no relevance when discussing the design and operation of today's modern LNG facilities.

LNG is cryogenic; it is a liquid; and its vapors are flammable. It is not without its safety concerns and risks. It, however, can be produced, transported and revaporized as safely, and in most cases, more safely, than other liquid energy fuels.

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APPENDIX A

Chronological Summary of Incidents Involving Land-Based LNG Facilities

1. October, 1944 Cleveland, Ohio, USA ~ *"The Cleveland Disaster"*

LNG Peakshaving Facility

Any time the topic of LNG is introduced to a new audience the *"Cleveland Disaster"* is bound to surface. It was indeed tragic, but an unbiased review will show just how far the industry has come since that horrific incident. The East Ohio Gas Company built the first "commercial" LNG peakshaving facility in Cleveland in 1941. The facility was run without incident until 1944, when a larger new tank was added. As stainless steel alloys were scarce because of World War II, the new tank was built with a low-nickel content (3.5%) alloy steel. Shortly after going into service, the tank failed. LNG spilled into the street and storm sewer system. The resultant fire killed 128 people, setting back the embryonic LNG industry substantially. The following information is extracted from the U.S. Bureau of Mines report[6] on the incident:

On October 20, 1944, the tanks had been filled to capacity in readiness for the coming winter months. About 2:15 PM, the cylindrical tank suddenly failed releasing all of its contents into the nearby streets and sewers of Cleveland. The cloud promptly ignited and a fire ensued which engulfed the nearby tanks, residences and commercial establishments. After about 20 minutes, when the initial fire had nearly died down, the sphere nearest to the cylindrical tank toppled over and released its contents. 9,400 gallons of LNG immediately evaporated and ignited. In all, 128 people were killed and 225 injured. The area directly involved was about three-quarters of a square mile (475 acres) of which an area of about 30 acres was completely devastated.

The Bureau of Mines investigation showed that the accident was due to the low temperature embrittlement of the inner shell of the cylindrical tank. The inner tank was made of 3.5% nickel steel, a material now known to be susceptible to brittle fracture at LNG storage temperature (minus 260°F). In addition, the tanks were located close to a heavily traveled railroad station and a bombshell stamping plant. Excessive vibration from the railroad engines and stamping presses probably accelerated crack propagation in the inner shell. Once the inner shell ruptured, the outer carbon steel wall would have easily fractured upon contact with LNG. The accident was aggravated by the absence of adequate diking around the tanks, and the proximity of the facility to the residential area. The cause of the second release from the spherical tank was the fact that the legs of the sphere were not insulated against fire so that they eventually buckled after being exposed to direct flame contact.

Further, it should be noted that the ignition of the two unconfined vapor

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6 *"Report on the Investigation of the Fire at the Liquefaction, Storage, and Regasification Plant of the East Ohio Gas Co., Cleveland, Ohio, October 20, 1944,"* U.S. Bureau of Mines, February, 1946.

clouds of LNG in Cleveland did not result in explosions. There was no evidence of any explosion overpressures after the ignition of the spill from either the cylindrical tank or the sphere. The only explosions that took place in Cleveland were limited to the sewers where LNG ran and vaporized before the vapor-air mixture ignited in a relatively confined volume. The U.S. Bureau of Mines concluded that the concept of liquefying and storing LNG was valid if "proper precautions are observed."

The Cleveland Disaster put an end to any further LNG development in the United States for many years. It was not until the early sixties that LNG began to be taken seriously through construction of LNG peakshaving facilities. A number of elements came together to bring LNG back; these included:

- The advent of the space program and its associated cryogenic technologies
- Successful large-scale fire and vapor cloud dispersion demonstrations
- Extensive cryogenic material compatibility studies
- Construction and operation of liquefaction plants in Algeria and receiving terminals in France and England.

2. May, 1965 Canvey Island, Essex, United Kingdom

LNG Import Terminal

A small amount of LNG spilled from a tank during maintenance. The spill ignited and one worker was seriously burned. No other details have been made available.

3. March, 1968 Portland, Oregon, USA

LNG Peakshaving Facility - *Construction Accident, no LNG present*

Four workers inside an unfinished LNG storage tank were killed when natural gas from a pipeline being pressure tested inadvertently entered the tank as a result of improper isolation, and then ignited causing an explosion. The LNG tank was 120 feet in diameter with a 100-foot shell height and a capacity of 176,000 barrels and damaged beyond repair. Neither the tank nor the process facility had been commissioned at the time the accident occurred. The LNG tank involved in this accident had never been commissioned; thus, it had never contained any LNG.

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4. 1971 La Spezia, Italy

LNG Import Terminal - *First documented LNG Rollover incident*

The LNG carrier *Esso Brega* had been in the harbor for about a month before unloading its cargo of "heavy" LNG into the storage tank. Eighteen hours after the tank was filled, the tank developed a sudden increase in pressure causing LNG vapor to discharge from the tank safety valves and vents over a period of a few hours. The roof of the tank was also slightly damaged. It is estimated that about 100 mmscf of LNG vapor (natural gas) flowed out of the tank. No ignition took place. This accident was caused by a phenomenon called "rollover,"[7] where two layers of LNG having different densities and heat content are allowed to form. The sudden mixing of these two layers results in the release of large volumes of methane vapor.

5. January, 1972 Montreal, Canada

LNG Peakshaving Facility - *Although an LNG facility, LNG was not involved*

On January 27, 1972 an explosion occurred in the LNG liquefaction and peak shaving plant of Gaz Métropolitain in Montreal East, Quebec. The accident occurred in the control room due to a back flow of natural gas from the compressor to the nitrogen line. Nitrogen was supplied to the recycle compressor as a seal gas during defrosting operations. The valves on the nitrogen line that were kept open during defrosting operation were not closed after completing the operation. This resulted in the over-pressurization of the compressor with up to 250 - 350 psig of natural gas. Natural gas entered the nitrogen header, which was at 75 psig. The pneumatically controlled instruments were being operated with nitrogen due to the failure of the instrument-air compressor. The instruments vented their contents into the atmosphere at the control panel. Natural gas entered the control room through the nitrogen header and accumulated in the control room, where operators were allowed to smoke. The explosion occurred while an operator was trying to light a cigarette.

6. February, 1973 Staten Island, New York, USA

LNG Peakshaving Facility - *Construction Accident, no LNG present*

Proper precautions have been common place in all of the LNG facilities built and placed in service ever since Cleveland (1944). Between the mid-1960s and mid-1970s more than 60 LNG facilities were built in the United States. These peak-shaving plants have had an excellent safety record. This <u>construction accident</u> has consistently been used by opponents of LNG as a case-in-point to depict the danger of LNG, after all, "40 persons lost their lives at an LNG facility."

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[7] See Section 3.1 of CH·IV's ***"Introduction to LNG Safety,"*** *Short Course on LNG Rollover.*

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Chronological Summary of Incidents Involving Land-Based LNG Facilities

Here's the story –

One of Texas Eastern Transmission Corporation's (TETCO) LNG storage tanks on Staten Island had been in service for over three years when it was taken out of service for internal repairs. The tank was warmed, purged of the remaining combustible gases with inert nitrogen and then filled with fresh recirculating air. A construction crew entered the tank to begin repair work in April of 1972. Ten months later, in February of 1973, an unknown cause ignited the Mylar liner and polyurethane foam insulation inside the tank. Initial standard operating procedures called for the use of explosion-proof equipment within the tank, however non-explosion proof irons and vacuum cleaners were being used for sealing the liner and cleaning insulation debris. It is assumed that an electrical spark in one of the irons or vacuum cleaners ignited the Mylar liner. The rapid rise in temperature caused a corresponding rise in pressure inside the tank. The pressure increase lifted the tank's concrete dome. The dome then collapsed killing the 40 construction workers inside.

The subsequent New York City Fire Department investigation[8] concluded that the accident was clearly a <u>construction accident</u> and not an LNG accident. This has not prevented LNG's opponents from claiming that since there may have been latent vapors from the heavy components of the LNG that was stored in the tank, then it was in fact an LNG incident.

7. March, 1977 Algeria

LNG Export Facility

A worker at the Camel plant was frozen to death when he was sprayed with LNG, which was escaping from a ruptured valve body on top of an in-ground storage tank. Approximately 1,500 to 2,000 m^3 of LNG were released, but the resulting vapor cloud did not ignite. The valve body that ruptured was constructed of cast aluminum. The current practice is to provide valves in LNG service that are made with stainless steel.

8. March, 1978 Das Island, United Arab Emirates

LNG Export Facility

A bottom pipe connection of an LNG tank failed resulting in an LNG spill inside the LNG tank containment. The liquid flow was stopped by closing the internal valve designed for just such an emergency. A large vapor cloud resulted and dissipated without ignition. No injuries or fatalities were reported.

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[8] ***"Report of Texas Eastern LNG Tank Fatal Fire and Roof Collapse, February 10, 1973,"*** Fire Department of the City of New York, July, 1973

9. October, 1979 Cove Point, Maryland, USA

LNG Import Terminal

The Cove Point LNG Receiving Terminal in Maryland began operations in the spring of 1978. By the fall of 1979, Cove Point had unloaded over 80 LNG ships. In 1979, a tragic accident occurred at Cove Point that took the life of one operator and seriously burned another.

Around 3:00 AM on October 6, 1979, an explosion occurred within an electrical substation at Cove Point. LNG had leaked through an inadequately tightened LNG pump electrical penetration seal, vaporized, passed through 200 feet of underground electrical conduit and entered the substation. Since natural gas was never expected in this substation, no gas detectors had been installed in the building. The natural gas-air mixture was ignited by the normal arcing contacts of a circuit breaker, resulting in an explosion. The explosion killed one operator in the building, seriously injured a second and caused about $3 million in damages.

The National Transportation Safety Board (NTSB) found[9] that the Cove Point Terminal was designed and constructed in conformance with all appropriate regulations and codes. It further concluded that this was an isolated incident, not likely to recur elsewhere. The NTSB concluded that it is unlikely that any pump seal, regardless of the liquid being pumped, could be designed, fabricated or installed to completely preclude the possibility of leakage. With that conclusion in mind, building codes pertaining to the equipment and systems downstream of the pump seal were changed. Before the Cove Point Terminal was restarted, all pump seal systems were modified to meet the new codes and gas detection systems were added to all buildings.

10. April, 1983 Bontang, Indonesia

LNG Export Facility - *Maintenance Accident, no LNG present*

A major incident occurred on April 14, 1983 in Bontang, Indonesia. The main liquefaction column (large vertical, spiral wound, heat exchanger) in Train B ruptured due to overpressurization caused by a blind flange left in a flare line during start-up. All the pressure protection systems were connected to this line. The exchanger experienced pressures three times its design pressure before rupturing. Debris and coil sections were projected some 50 meters away. Shrapnel from the column killed three workers. The ensuing fire was extinguished in about 30 minutes. This incident occurred during dry-out and purging of the exchanger with warm natural gas prior to introducing any LNG into the system, so <u>no LNG was actually involved or released</u>.

[9] "Columbia LNG Corporation Explosion and Fire; Cove Point, MD; October 6, 1979" National Transportation Safety Board Report NTSB-PAR-80-2, April 16, 1980

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APPENDIX A

Chronological Summary of Incidents Involving Land-Based LNG Facilities

11. August, 1985 Pinson, Alabama, USA

LNG Peakshaving Facility

The welds on an 8¼ inch by 12 inch "patch plate" on a small aluminum vessel (3 feet in diameter by 7 feet tall) failed as the vessel was receiving LNG which was being drained from the liquefaction cold box. The plate was propelled into a building that contained the control room, boiler room and offices. Some of the windows in the control room were blown inward and natural gas escaping from the failed vessel entered the building and ignited. Six employees were injured.

12. 1987 Mercury, Nevada, USA

Department of Energy Test Facility

An accidental ignition of an LNG vapor cloud occurred at the DOE, Nevada Test Site on August 29, 1987. The large-scale tests involving spills of LNG on water were sponsored by the Department of Energy and Gas Research Institute to study the effectiveness of vapor fences in reducing the extent of downwind dispersion of LNG vapor clouds. The cloud accidentally ignited during Test #5 just after a sequence of relatively strong rapid phase transitions (RPTs) which damaged and propelled polyurethane pipe insulation outside the fence.

The official explanation was that a spark generated by static electricity approximately 76 seconds after the spill was the most likely source of ignition. An independent investigation on behalf of Gas Research Institute showed that a more likely source of ignition was oxygen enrichment between the surface of the LNG pipe and the combustible polyurethane foam insulation. Oxygen enrichment occurred during the long cool-down period with liquid nitrogen that preceded the LNG test. Such enrichment had been previously observed during tests carried out by an LNG tank design and manufacturing company. Impacts during the RPTs may have ignited the insulation but not the nearby fuel-rich vapor cloud. However, when a smoldering insulation fragment was propelled outside the fence by an RPT, it ignited the portion of the cloud that was within the flammable limits. The duration of the fire was 30 seconds. The flame length was about 20 feet above the ground.

There have been other accidental ignitions involving LNG during large-scale tests.

- One occurred in England during large-scale fire tests being carried out by British Gas Corporation. Stray currents from a nearby radar station were blamed for prematurely igniting the primer that was eventually to be used to ignite the LNG cloud.
- Another occurred in Japan during similar large-scale tests carried out by

Japan Gas Association. The ignition mechanism was not explained.

- During a test at a research facility near San Clemente, California, a sudden change in wind direction caused the vapor cloud to encounter a tractor that was moving some of the test equipment. The tractor ignited the vapor cloud, badly burning the driver. A researcher was also in the vapor cloud at the time of ignition. He was able to get out of the vapor cloud before the flame front reached him by running crosswind and was not injured.

13. 1988 Everett, Massachusetts, USA

LNG Import Terminal

Approximately 30,000 gallons of LNG were spilled through "blown" flange gaskets during an interruption in LNG transfer at Distrigas. The cause was later determined to be "condensation induced water hammer."[10] The spill was contained in a small area, as designed. The still night prevented the movement of the vapor cloud from the immediate area. No one was injured and no damage occurred beyond the blown gasket. Operating procedures, both manual and automatic, were modified as a result.

14. 1989 Thurley, United Kingdom

LNG Peakshaving Facility

While cooling down the vaporizers in preparation for sending out natural gas, low-point drain valves were opened on each vaporizer. One of these drain valves had not been closed when the pumps were started and LNG entered the vaporizers. As a result, LNG was released into the atmosphere as a high-pressure jet. The resulting vapor cloud ignited about thirty seconds after the release began. The flash fire covered an area approximately 40 by 25 m. Two operators received burns to their hands and faces. The source of ignition was believed to be the pilot light on one of the other submerged combustion vaporizers.

15. December 9, 1992 Baltimore, Maryland, USA

LNG Peakshaving Facility

A relief valve on LNG piping near one of the three LNG tanks failed open and released LNG into the LNG tank containment for over 10 hours, resulting in an estimated loss of over 25,000 gallons into the LNG tank containment. The LNG also impinged on the LNG tank causing embrittlement fractures on the outer shell. The LNG tank was taken out of service and repaired. No plant personnel were injured, no vapor was ignited and none traveled outside the plant area.

[10] See description in Section 3.1 of CH·IV's ***"Introduction to LNG Safety"***

Safety History of International LNG Operations

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Chronological Summary of Incidents Involving Land-Based LNG Facilities

16. 1993 Bontang, Indonesia

LNG Export Facility

An LNG leak occurred in the open run-down line during a pipe modification project in Train E. LNG entered an underground concrete oily-water sewer system and underwent a rapid vapor expansion that overpressured and ruptured the sewer pipes. No ignition of the vapor occurred, but the sewer system and some nearby equipment was damaged. There were no injuries.

17. September, 2000 Savannah, Georgia, USA

LNG Import Terminal

In September 2000, a 580-foot ship, the Sun Sapphire, lost control in the Savannah River and crashed into the LNG unloading pier at Elba Island. The Elba Island facility was undergoing reactivation but had no LNG in the plant. The Sun Sapphire, carrying almost 20,000 tons of palm and coconut oil, suffered a 40-foot gash in her hull. The point of impact at the terminal was the LNG unloading platform. Although the LNG facility experienced significant damage, including the need to replace five 16" unloading arms, there was no indication that had LNG been present in the piping that there would have been a release. Given the geometry of the Savannah River at Elba Island, it is doubtful that had an LNG ship been present that a similar ramming could have penetrated the double hull and released any LNG.

18. August 16, 2003 Bintulu, Malaysia

LNG Liquefaction and Export Facility

A major fire occurred in the exhaust system of the propane compressor gas turbine in the first train (train 7) of the MLNG Tiga project. A crack had developed in the joint between the tube and header of the regeneration gas coil in the waste heat recovery unit (WHRU). This leakage went undetected. The propane compressor and turbine experienced a trip that was unrelated to the gas leakage. The procedure was then for the turbine to go into a slow rotation of 6 rpm using the barring motor, which successfully occurred. Because of the rotation of the turbine blades and the chimney effect of the turbine exhaust stack, air was drawn in through the turbine and into the exhaust duct. The natural gas escaping from the regeneration coil crack mixed with the air inside the WHRU that was still at a very high temperature, near the normal operating exhaust temperature of 570°C. When the gas air mixture reached its lower flammability limit and auto ignition temperature of 537 °C, an explosion inside the WHRU resulted. The incident caused damage to the WHRU ducting, hot oil and regeneration coils gas turbine and compressors, as well as superficial damage to the compressor building. No injury occurred to any personnel. While the incident involved natural gas and was in an auxiliary system for one of the major pieces of the refrigeration system it did not directly involve LNG or any part of the cryogenic systems.

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Chronological Summary of Incidents Involving Land-Based LNG Facilities

19. January 19, 2004 Skikda, Algeria

LNG Liquefaction and Export Facility

A leak in the hydrocarbon refrigerant system formed a vapor cloud that was drawn into the inlet of a steam boiler. The increased fuel to the boiler caused rapidly rising pressure within a steam drum. The rapidly rising pressure exceeded the capacity of the boiler's safety valve and the steam drum ruptured. The boiler rupture was close enough to the gas leak area to ignite the vapor cloud and produce an explosion due to the confined nature of the gas leak and an ensuing fireball. The fire took eight hours to extinguish. The explosions and fire destroyed a portion of the LNG plant and caused 27 deaths and injury to 72 more. No one outside the plant was injured nor were the LNG storage tanks damaged by the explosions. A joint report[11] by the U.S. Federal Energy Regulatory Commission (FERC) and the U.S. Department of Energy (DOE) was issued in April 2004. The findings in the report indicate that there were local ignition sources, a lack of "typical" automatic equipment shutdown devices and a lack of hazard detection devices.

20. 2009 Tangguh, Indonesia

LNG Liquefaction and Export Facility

A leak occurred at the manifold on the LNG storage tank platform when the LNG was being pumped from the storage tank. As a result, LNG hit the carbon steel tank roof plates causing cracks and methane gas to leak out in several places. It was speculated by knowledgeable sources that the leak was the result of incorrect torque being applied to various flange bolts and incorrect pipe spring hanger settings during the cool-down process. Facilities had only been in operation for a short time and this may have been the initial cooling down of the tank pump discharge piping.

21. September 8, 2011, Rotterdam, Netherlands

LNG Import Terminal

During maintenance works on one of the jetties of Gate terminal a small amount of natural gas was released. This caused a visible white cloud at the jetty. The condensation of air humidity following the contact with the cold gas caused this cloud. The cloud itself does not contain any toxic substances and there was no danger for the nearest residential neighborhood. In coordination with the authorities the port stopped ship movements for a while in the immediate surroundings of the terminal at the Maasvlakte. The release of gas was stopped and ship movements resumed shortly afterwards.

[11] "Report of the U.S. Government Team Site Inspection of the Sonatrach Skikda LNG Pant in Skikda, Algeria, March 12-16, 2004"

Safety History of International LNG Operations

APPENDIX B

Chronological Summary of Incidents Involving LNG Ships

1. 1964/1965

25,500 M^3 *Jules Verne*

While loading LNG in Arzew, Algeria, lightning struck the forward vent riser of the ship and ignited vapor, which was being routinely vented through the ship venting system. Loading had been stopped when a thunderstorm broke out near the terminal but the vapor generated by the loading process was being released to the atmosphere. The shore return piping had not yet been in operation. The flame was quickly extinguished by purging with nitrogen through a connection to the riser.

A similar event happened early in 1965 while the vessel was at sea shortly after leaving Arzew. The fire was again extinguished using the nitrogen purge connection. In this case, vapor was being vented into the atmosphere during ship transit, as was the normal practice at that time.

2. May, 1965

27,400 M^3 *Methane Princess*

The LNG loading arms were disconnected before the liquid lines had been completely drained, causing LNG to pass through a leaking closed valve and into a stainless steel drip pan placed underneath the arms. Seawater was applied to the area. Eventually, a star-shaped fracture appeared in the deck plating in spite of the application of the seawater.

3. May, 1965

25,500 M^3 *Jules Verne*

On the fourth loading of Jules Verne at Arzew in May 1965 an LNG spill, caused by overflowing of Cargo Tank No.1, resulted in the fracture of the cover plating of the tank and of the adjacent deck plating. The cause of the over-fill has never been adequately explained, but it was associated with the failure of liquid level instrumentation and unfamiliarity with equipment on the part of the cargo handling watch officer.

4. April 11, 1966

27,400 M^3 *Methane Progress*

Cargo leakage reported. No details.

5. September, 1968

5,000 M^3 *Aristotle*

Ran aground off the coast of Mexico. Bottom damaged. Believed to be in LPG service and not carrying LNG when this occurred. *No LNG released.*

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6. November 17, 1969

71,500 M^3 *Polar Alaska*

Sloshing of the LNG heel in No. 1 tank caused part of the supports for the cargo pump electric cable tray to break loose, resulting in several perforations of the primary barrier. LNG leaked into the interbarrier space. *No LNG released.*

7. September 2, 1970

71,500 M^3 *Arctic Tokyo*

Sloshing of the LNG heel in No. 1 tank during bad weather caused local deformation of the primary barrier and supporting insulation boxes. LNG leaked into the interbarrier space at one location. *No LNG released.*

8. Late 1971

50,000 M^3 *Descartes*

A minor fault in the connection between the primary barrier and the tank dome allowed gas into the interbarrier space. *No LNG released.*

9. June, 1974

27,400 M^3 *Methane Princess*

On June 12, 1974 the *Methane Princess* was rammed by the freighter *Tower Princess* while moored at Canvey Island LNG Terminal and created a 3-foot gash in the outer hull. *No LNG released.*

10. July, 1974

5,000 M^3 *Barge Massachusetts*

LNG was being loaded on the barge on July 16, 1974. After a power failure and the automatic closure of the main liquid line valves, a small amount of LNG leaked from a 1-inch nitrogen-purge globe valve on the vessel’s liquid header. The subsequent investigation by the U.S. Coast Guard found that a pressure surge caused by the valve closure induced the leakage of LNG through the bonnet and gland of the 1-inch valve. The valve had not leaked during the previous seven or more hours of loading. Several fractures occurred in the deck plates where contacted by the LNG spill. They extended over an area that measured about one by two meters. The amount of LNG involved in the leakage was reported to be about 40 gallons. As a result of this incident, The U.S. Coast Guard banned the Barge Massachusetts from LNG service within the U.S. It is believed that the Barge Massachusetts is now working overseas in liquid ethylene service.

11. August, 1974

4,000 M^3 *Euclides*

Minor damage was reported due to contact with another vessel. *No LNG released.*

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Chronological Summary of Incidents Involving LNG Ships

12. November, 1974

4,000 M^3 *Euclides*

Ran aground at La Havre, France. Damaged bottom and propeller.

No LNG released.

13. 1974

27,400 M^3 *Methane Progress*

The ship ran aground at Arzew, Algeria. Damaged rudder. *No LNG released.*

14. September, 1977

125,000 M^3 *LNG Aquarius*

During the filling of Cargo Tank No. 1 at Bontang on September 16, 1977, LNG overflowed through the vent mast serving that tank. The incident may have been caused by difficulties in the liquid level gauge system. The high-level alarm had been placed in the override mode to eliminate nuisance alarms. Surprisingly, the mild steel plate of which the cargo tank cover was made did not fracture as a result of this spill.

15. August 14, 1978

124,890 M^3 *Khannur*

Collision with a cargo ship, *Hong Hwa,* in the Strait of Singapore was reported. Minor damage was indicated.

No LNG released.

16. April, 1979

125,000 M^3 *Mostefa Ben Boulaid*

While discharging cargo at Cove Point, Maryland on April 8, 1979, a check valve in the piping system of the vessel failed releasing a small quantity of LNG. This resulted in minor fractures of the deck plating. This spill was caused by the escape of LNG from a swing-check valve in the liquid line. In this valve, the hinge pin is retained by a head bolt, which penetrates the wall of the valve body. In the course of operating the ship and cargo pumping system, it appears that the vibration caused the bolt to back out, releasing a shower of LNG onto the deck. The vessel was taken out of service after the incident and the structural work renewed. All of the check valves in the ship's liquid system were modified to prevent a recurrence of the failure. A light stainless steel keeper was fashioned and installed at each bolt head. Shortly after the ship returned to service, LNG was noticed leaking from around one bolt head, the keeper for which had been stripped, again probably because of vibration. More substantial keepers were installed and the valves have been free from trouble since that time.

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17. April, 1979

87,600 M^3 *Pollenger*

While the Pollenger was discharging LNG at the Distrigas terminal at Everett, Massachusetts on April 25, 1979, LNG leaking from a valve gland apparently fractured the tank cover plating at Cargo Tank No. 1. The quantity of LNG that spilled was probably only a few liters, but the fractures in the cover plating covered an area of about two square meters.

18. June 29, 1979

125,000 M^3 *El Paso Paul Kayser*

The Carrier ran aground at 14 knots while maneuvering to avoid another vessel in the Strait of Gibraltar. Bottom damaged extensively. Vessel refloated and cargo transferred to sister ship, the *El Paso Sonatrach*. *No LNG released.*

19. December 12, 1980

125,000 M^3 *LNG Taurus*

Ran aground in heavy weather at Mutsure Anchorage off Tobata, Japan. Bottom damaged extensively. Vessel refloated, proceeded under its own power to the Kita Kyushu LNG Terminal, and cargo discharged. *No LNG released.*

20. Early 1980s

125,000 M^3 *El Paso Consolidated*

Minor release of LNG from a flange. Deck plating fractured due to low temperature embrittlement.

21. Early 1980s

129,500 M^3 *Larbi Ben M'Hidi*

Vapor released during transfer arm disconnection. *No LNG released.*

22. December, 1983

87,600 M^3 *Norman Lady*

During cooldown of the cargo transfer arms, prior to unloading at Sodegaura, Japan, the ship suddenly moved astern under its own power. All cargo transfer arms sheared and LNG spilled. No ignition.

23. 1985

35,500 M^3 *Isabella*

LNG released as a result of overfilling a tank. Deck fractured due to low temperature embrittlement.

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Chronological Summary of Incidents Involving LNG Ships

24. 1985

35,500 M^3 *Annabella*

Reported as "pressurized cargo tank." Presumably, some LNG released from the tank or piping. No other details are available.

25. 1985

126,000 M^3 *Ramdane Abane*

Collision while loaded. Port bow affected. *No LNG released.*

26. February, 1989

40,000 M^3 *Tellier*

Wind blew ship from its berth at Skikda, Algeria. Cargo transfer arms sheared. Piping on ship heavily damaged. Cargo transfer had been stopped. According to some verbal accounts of this incident, LNG was released from the cargo transfer arms.

27. Early 1990

125,000 M^3 *Bachir Chihani*

A fracture occurred at a part of the ship structure, which is prone to the high stresses that may accompany the complex deflections that the hull encounters on the high seas. Fracture of the inner hull plating led to the ingress of seawater into the space behind the cargo hold insulation while the vessel was in ballast.

No LNG released.

28. May 21, 1997

125,000 M^3 *Northwest Swift*

Collided with a fishing vessel about 400 km from Japan. Some damage to hull, but no ingress of water. *No LNG released.*

29. October 31, 1997

126,300 M^3 *LNG Capricorn*

Struck a mooring dolphin at a pier near the Senboku LNG Terminal in Japan. Some damage to hull, but no ingress of water. *No LNG released.*

30. September 6, 1999

71,500 M^3 *Methane Polar*

Engine failure during approach to Atlantic LNG jetty (Trinidad and Tobago). Struck and damaged Petrotrin pier. No injuries. *No LNG released.*

31. December 2002

87,000 M^3 *Norman Lady*

A U.S. nuclear submarine, the U.S.S. Oklahoma City, raised its periscope into the ship necessitating her withdrawal briefly from service for repairs due to penetration of outer hull allowing leakage of seawater. *No LNG released*

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32. December 15, 2009

126,500 M^3 *Matthew*

The 920-foot Norwegian LNG tanker Matthew was grounded, half a mile southeast of Cayo Caribe near Guayanilla, Puerto Rico. The crew shifted some of the cargo and the vessel was refloated after about three hours with the help of two tugboats. The Matthew proceeded to the EcoElectrica Punta Guayanilla LNG terminal to discharge and receive surveys. Authorities say investigators found no signs of a spill or other environmental damage from the grounding.

No LNG released

33. 2010

145,000 M^3 *Bluesky*

The TMT-controlled carrier was damaged at GDF Suez's Montoir de Bretagne terminal in France when a valve was by-passed and liquid passed into the gas take-off line during discharge operations. The damage sustained extended to part of the ship's manifold and its feed lines without damage to the shore-side systems.

No LNG release was reported

34. March 1, 2010

126,500 M^3 *LNG Edo*

During loading operations at the Bonny LNG terminal in Nigeria, LNG Edo took a significant list. Cargo loading operations were suspended. The cause of the list was found to be abnormal ballast water distribution in the ship's tanks. The distribution in the ballast tanks was returned to normal and loading was completed in a normal manner on March 4th. There were no injuries to personnel nor was there any pollution or damage to either the vessel or the jetty. The vessel subsequently discharged cargo at Sines, Portugal, on March 13th and 14th without incident.

No LNG released

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Chronological Summary of Incidents Involving LNG Ships

Yuyo Maru No. 10

The following information pertains to a liquid petroleum gas tanker (LPG) which has a similar construction to an LNG tanker. The information was obtained from a Japanese marine registry record. The annotations [text] *were added by the authors for clarity. This incident is included in this document to help illustrate the integrity of LNG tanks onboard LNG ships. There is much discussion today around the impact of a terrorist attack perpetrated on an LNG tanker.*

The Motorship "Yuyo Maru No. 10" (gross tonnage of 43,723), laden with 20,831 MT of light naphtha, 20,202 MT of propane and 6,443 MT of butane, left Ras Tanura, in the Kingdom of Saudi Arabia, for Kawasaki, and the port of Keihin on October 22, 1974. While the vessel was sailing northward along the Naka-no Se Traffic Route in Tokyo Bay on November 9, she collided with the Motorship "Pacific Ares" (gross tonnage of 10,874), manned with a Taiwanese Master and 28 crew members, laden with 14,835 MT of steel products, en route from Kisarazu for Los Angeles, USA. The collision occurred about 13:37 hours on the same day slightly northward of the boundary line of the Naka-no Se Traffic Route.

As a result of the collision, the "Yuyo Maru No. 10" suffered a large hole at the point of collision, with her cargo naphtha [The naphtha was carried in its outer ballast tank (between the insulated LPG tanks and the hull of the ship). This is effectively what makes up the "double hull" with LNG ships. The LPG cargo tank was not penetrated. LNG tankers never carry any thing other than air or ballast (water) in these tanks.] instantly igniting into flames. As a result of the outflow of naphtha overboard, the sea surface on her starboard side literally turned into a sea of fire. The "Pacific Ares" showered with fire burst into flames in the forecastle and on the bridge. While explosions occurred one after another [naphtha, not propane], attempts were made to tow the "Yuyo Maru No 10", outside the bay, but she ran aground in the vicinity of Daini Kaiho. She was successfully towed out of Tokyo Bay and sunk south of Nojima Saki on the afternoon of November 27 [Thirty-six days after the original collision.] by cannon, air bomb and torpedo attacks staged by the Maritime Self-Defense Force. [Please note "cannon, air bomb and torpedo attacks" were required to sink the ship. Other reports indicate that these attacks lasted one and a half days. The author has seen a black and white film of these attacks. It appeared that the LPG tanks were for the most part fully in tact prior to the attacks. The ship's LPG vent stacks were melted down to just above the decks and on fire indicating that LPG remained within the storage tanks.]

On board the "Yuyo Maru No. 10", five crew members were killed and seven others injured by this accident. The "Pacific Ares", whose forward section was completely crushed and superstructures burned down, was later repaired. Her crew members were all killed except one person, who was injured but rescued.

Safety History of International LNG Operations

APPENDIX C

Chronological Summary of LNG Tanker Truck Incidents

	Date	Location	LNG Carrier
1.	June 1971	Waterbury, VT	Capitol
	Blowout, hit rocks by road, tore hole in tank, 20% spilled, no fire, remainder dumped.		
2.	August 1971	Warner, NH	Gas, Inc.
	Driver fatigue, drove off road, rollover cracked fittings, small gas leak, no fire.		
3.	October 1971	N. Whitehall, WI	Indianhead
	Head-on collision with truck. Gasoline and tire fire, no cargo lost.		
4.	October 1973	Raynham, MA	Andrews & Pierce
	Truck side swiped parked car; brakes locked and trailer overturned. No cargo on-board, no fire		
5.	1973	Rt. 80 & 95 JCT, NJ	Chemical Leaman
	Driver couldn't negotiate turn off. Rollover demolished tractor and severe damage to trailer. No fire. $40,000 damage to trailer.		
6.	February 1974	New Jersey Turnpike	Gas, Inc.
	Faulty brakes caused wheel fire. Check valve cracked 5% leaked out. No fire.		
7.	February 1974	McKee City, NJ	Gas, Inc.
	Loose valve leaked LNG during transfer operation.		
8.	January 1976	Chattanooga, TN	LP Transport
	Rollover, no fire, caused by oil spill on exit ramp. Truck righted and continued delivery of cargo.		
9.	November 1975	Dalton, GA	LP Transport
	Rollover, no fire. Driver swerved to avoid pedestrian, hit guardrail and rolled over and down an 80 foot bank. $18,000 damage to trailer.		
10.	September 1976	Pawtucket, RI	Andrews & Pierce
	Car hit trailer at landing wheels, rollover, no LNG loss or fire.		
11.	April 1977	Connecticut Turnpike	Chemical Leaman
	Truck parked (with blowout) hit by a tow truck in rear. No leak or fire.		
12.	July 1977	Waterbury, CT	LP Transport
	"Single Wall" Lubbock hit in rear by tractor-trailer, axle knocked off. Rollover. No loss of cargo.		
13.	December 1977	I5 & I10, Los Angeles	Western Gillet/SDG
	Rollover with little product loss, no vacuum loss, no fire. Driver had 3 broken ribs.		

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APPENDIX C

Chronological Summary of LNG Tanker Truck Incidents

	Date	Location	LNG Carrier
14.	February 1981	Barnagat, NJ	LP Transport

Driver failed to negotiate turn due to excessive speed on country road. Driver not hurt seriously. Loss of some product through relief valve resulted in serious damage to transport.

15. September 1981 — Lexington, MA — Andrews & Pierce

Rollover, no fire, no product loss (empty), driver not seriously hurt. Extensive damage to transport. Cause: rain and poor road conditions.

16. October, 1993 — Everett, MA — TransGas

Trailer slide off fifth wheel just before entering highway. No fire, no product loss

17. May 1994 — Revere, MA — TransGas

Trailer over turned when trying to negotiate a traffic circle at too high of speed. No product loss, no fire. Trailer emptied into second trailer without incident.

18. October 1998 — Woburn, Ma — TransGas

Trailer traveling at high speed is sideswiped by car then careens into guardrail ripping open diesel fuel tanks. Ensuing diesel fuel fire traps driver in cab where he perishes. Fire engulfs LNG trailer until extinguished. No loss of product experienced. LNG partially transferred to second trailer. Trailer then uprighted and sent to transport yard to complete the transfer of product.

19. June 22, 2002 — Tivissa, Catalonia, Spain — Not Available

An LNG road tanker overturned and caught fire on the C-44 road and subsequently (about 20 minutes later) suffered a significant LNG fire, the first such LNG-related trucking incident reported. However, the design of the trailer involved was very different from that used in the U.S. It was simply a pressure vessel insulated externally with unprotected polyurethane insulation, whereas cryogenic trailers in the U.S. are double-walled, vacuum-jacketed pressure vessels. When the trailer overturned the insulation was readily scraped off the pressure vessel and directly exposed to the fire. It is unclear what actually caused the leakage of LNG, but U.S trailers in addition to having the outer tank protection also have recessed protected piping further reducing the potential for leakage due to overturning. Due to severe nature of the accident, the driver died and a woman who was reportedly about 200m away from the truck suffered second degree burns.

20. September 2003 — Woburn, Ma — TransGas

Trailer traveling too fast on a highway exit ramp overturned. There was no leakage of cargo from the overturned truck. The truck driver was slightly injured and received a speeding citation.

See Note at end of next page.

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Chronological Summary of LNG Tanker Truck Incidents

Date	Location	LNG Carrier
21. September 14, 2005	Near Reno, NV	Logistics Express

The driver of an LNG tractor trailer stopped at a truck stop on I-80 near Reno and noticed that LNG was leaking from the fireblock valve. He notified the local emergency responders. Shortly after their arrival the LNG vapor ignited. The on-scene emergency responders decided to first close the Interstate and evacuate people from local businesses and residences and then expand the evacuation area for about three hours. When the fire subsided, the evacuation was cancelled. The trailer performed as designed and there was no loss of vacuum on the trailer double wall system. The trailer was removed from service for minor damage repair and returned to service within a week. Unfortunately, the emergency responders did not understand LNG or the design of LNG trailers or they would not have executed such a large evacuation.

22. October 11, 2007 — Province of Cadiz, Spain — Not Reported

An LNG truck carrying a load of 19,200 Kg of LNG slid down a bank of about 3 meters at a cross road in the province of Cadiz in Spain. There was no LNG released or spilled. Although the accident caused small fires from the burning truck fuel, none were LNG related. The truck driver who was trapped under the damaged vehicle died. The cause of the accident was not reported.

23. August 23, 2011 — Istanbul, Turkey — Not Reported

A tanker truck loaded with liquefied natural gas (LNG) got stuck under a three-and-a-half-meter-high overpass in İstanbul. The incident took place in Ataköy, Bakırköy district. The driver attempted to push through, but had to call police for help once he realized that it would not be possible for him to pass underneath.
Police and fire brigade teams were able to dislodge the vehicle. There was no LNG spill.

> Note: Incidents 16, 17, 18 and 20 were reported on television and/or presented in the local Boston print media. In every case the media attempted to create a disaster scenario using meaningless phases such as *"blast zone"* and *"police cruisers turned off lights to prevent explosions."* In one case a totally misinformed fire chief stated that the situation was "*potentially a giant bomb. . . . An explosion would devastate a half-mile in all directions.*" One of the worst "facts" reported was that *"water was hosed onto the tanker to keep the LNG cool"*! Unfortunately, the emergency responders near Reno, NV (as detailed above in incident number 21) had the same misconceptions about the explosive nature of LNG.