INTRODUCTION

The role of Pyeongtaek terminal is one of base-load Liquefied Natural Gas (LNG) receiving terminals in Korea Gas Corporation (KOGAS). The terminal received the first LNG cargo for its commissioning work at the end of October in 1986. The original design of the terminal includes one LNG unloading berth, four LNG storage tanks (Membrane type, 100,000 m³ each), and 530 t/h 600 MMscfd re-gasification facilities. It didn’t take long to decide to expand its capacity to over 2000 t/h (2.3 bcfd) in order to meet the abrupt increase in natural gas demand. The terminal added consecutively LNG storage tanks, re-gasification facilities, and an unloading berth. Presently, 10 units of storage tanks are under operation with a total capacity of one million kiloliter. Figure 1 shows the conceptual schematic of LNG process at the Pyeongtaek terminal.

During 17 years of operation of the terminal, the existing conventional designs have been improved upon enhancing the terminal reliability, achieving high controllability, and keeping a high level of safety. Terminal operator’s design improvements, as well as experiences in operation and maintenance, are valuable for the LNG industry. However, the operation feedbacks have been limited so far even though their role of LNG Receiving Terminal is important in an LNG chain.

This paper presents the terminal operator’s practical design improvements against the conventional design problems occurred unexpectedly during terminal operation and maintenance. These involve boil-off gas treatment, sendout pressure control, and LNG unloading. A tie-in work control procedure is discussed, which ensures safe terminal operation and enhances constructability.
during expansion work. This paper also proposes a new methodology to estimate the terminal sendout availability based on unit system availability and equipment reliability obtained from the actual accumulated operation and maintenance records.

**PRACTICAL DESIGN IMPROVEMENTS**

**Boil-off Gas Treatment**

The total vapor of LNG can be divided into two categories. One is re-gasified gas from cold energy utilization terminals and the other is Boil-Off Gas (BOG) from LNG storage tanks and equipment with relevant piping system. The BOG was originally designed to be compressed (10 barg.) and sent to an adjacent Pyeongtaek thermal power terminal as fuel. In addition, the low pressure (LP) vapor returned from an LNG cold air separation plant was also lined up to the power plant. The conversion of fuel from natural gas to bunker-C oil at the thermal power plant pressed the terminal to change its process. KOGAS decided to install a BOG re-liquefaction system using a sub-cooled LNG re-condenser at the terminal. This caused a revision in the original operating philosophy of the terminal.

The BOG in an LNG receiving terminal under normal operation is the result of heat being added to the LNG by heat fluxes through the walls from the surroundings of the LNG tanks, equipment, and associate piping system. Pump efficiency also contributes to the generation of BOG. The BOG is mainly composed of methane (over 99 %). The major portion of BOG comes out from LNG storage tanks. The BOG rate increases when LNG is unloaded from an LNG cargo to storage tanks due to the difference of saturation pressure and temperature between LNG cargo and storage tanks. The accumulated latent heat during LNG cargo voyage also increases BOG during unloading LNG, which is called a flashing phenomenon.

The amount of BOG was precisely estimated using a computer system under normal and unloading conditions. The rate of evaporation of LNG from a storage tank is essentially controlled by the amount of supersaturated pressure of the stored LNG and surface area of the vapor-liquid interface. The following Hashemi et al.\(^1\) model was used to estimate the BOG rate, \(m_{BOG}\):

\[
m_{BOG} = 0.04\Delta P_s^{4/3} \quad \left[ \text{Kg} / \text{hr} - \text{m}^2 \right] \quad \text{..........................................................} \quad (1)
\]

where, \(\Delta P_s\) is supersaturated pressure. It is a function of the average rate of change in the saturation temperature of the liquid with pressure, \(dT/dP\), and the total temperature difference between the bulk of the liquid and the surface, \(\Delta T_s\):

\[
\Delta P_s = \left( \frac{dT}{dP} \right)_{avg} \Delta T_s \quad \text{..........................................................} \quad (2)
\]

Additional vapor can be generated when certain conditions arise. Two conditions often observed and considered in this estimation were.

(1) tank pressure drop when barometer reading falls or the vapor withdrawal increases, and
(2) sub-cooled liquid reaching the surface from the bulk beneath or from the wall ascending boundary layer.

The total BOG rate depends on the terminal operating mode, season, temperature, day/night, etc. It varies from 15 to 50 t/h. The main reason for this large fluctuation is due to LNG unloading operation. The BOG was mixed with the LP re-gasified gas after compression by six sets of two stages reciprocating BOG compressors. The design capacity of each compressor is 12,000 Nm\(^3\)/h of BOG with a maximum discharge gauge pressure of 10.6 bar and a discharge temperature range from 14 to 47 °C. The vapor of the compressed BOG and returned re-gasified gas from cold energy utilization plant were used as fuel gas for the tank vacuum breaker, internal consumption (gas firing absorbed type heating/chilling unit), and neighboring KIA Motors.

The basic principle of the re-liquefaction system is to cool, re-liquefy, and send-out the excess vapor of natural gas by mixing it with sub-cooled low pressure LNG taken from the LP LNG header line. LNG stored in a storage tank is slightly above or at its saturation point at the operating pressure of the
tank (Point A, Fig. 2). After pressurization by the primary pumps, the LNG is sub-cooled (Point D, Fig. 2). It is, therefore, capable of absorbing a certain quantity of heat whilst remaining liquid. In particular, it can absorb the heat required for the condensation of the BOG up to the saturated point (Point E, Fig. 2). In order to improve the heat and mass transfer of gas and liquid phases, the condensation takes place in a packed tower where gas and liquid enter the top of the re-condenser and flow co-currently through the bed of metal rings, where both phases come in close contact. The re-condenser operating level is carefully monitored and maintained at half height. If re-condensing heat exchanger level rises, the stepwise overfilling protection system will be initiated.

In order to analyze the possibility of re-liquefaction using sub-cooled LNG, the gas supply pattern was investigated. Figure 3 shows the monthly gas send-out patterns. The amount of LP gas send-out was excluded in the design of the re-liquefaction system because the adjacent thermal power plant planned to switch the main fuel to bunker-C oil. The LNG flow rate also varies with gas demand, seasons, and ambient temperature. The gas supply in June was recorded as the lowest gas send-out. In order to secure the design of the system, the hourly gas supply patterns were also investigated. This study showed that gas demand had significantly dropped early in the morning (02:00 – 05:00 am). The lowest hourly gas supply was observed in June as shown in Fig. 4. The BOG rate is also decreased with a decrease in temperature in early in the morning.

If the liquid inlet flow rate and temperature are kept constant, the re-liquefaction system can be operated at low pressure when the gas flow rate and temperature are low. When the amount of vapor is high, the re-liquefaction system should be operated at high pressure. In practice, the re-liquefaction system having normal operating range 2 to 8.0 barg can liquefy all vapor up to 60 t/h if LNG liquid flow is over 450 t/h. In this case, the LNG should be sub-cooled under –155 °C and 8.5 barg. The mixing of ambient temperature gas with cold LNG in re-condensing heat exchanger will increase the temperature of the LNG at the secondary pump suction to –130 °C. Therefore, an increase in temperature of mixed LNG decreases the liquid density from 445 to 417 Kg/m³. The temperature and density of mixed LNG depends on the temperature and flow coming to the re-condenser of both the LNG and vapor of natural gas. Figure 5 shows the process flow diagram for gas re-liquefaction system.
Fig. 3 – Comparison of monthly gas supply pattern

Fig. 4 – Gas hourly supply pattern in June 1996 as a design basis
The density of the mixed LNG at the secondary pump suction header is different from the density initially used in design of the HP pumps. The density depends on the ratio of vapor re-liquefied with its temperature and the LNG flow fed to the re-condensing heat exchanger. Consequently, the changes in liquid density affect pump performance. The performance of a pump depends on its performance curve, which gives the barometric head (h) as a function of the volumetric rate (V). In order to pressurize LNG up to the operating pressure (76 barg), the barometric head should be increased from $h_1$ to $h_2$ when the liquid density is decreased. Then, the pumping volume is reduced from $V_1$ to $V_2$ as shown in Fig. 6. Effects of LNG density variation on pump operating conditions are presented in Table 1.
Table 1 – Effects of LNG density variation on pump performance

<table>
<thead>
<tr>
<th>Pump characteristics</th>
<th>Unit</th>
<th>Design</th>
<th>Before gas re-liquefaction</th>
<th>After gas re-liquefaction</th>
</tr>
</thead>
<tbody>
<tr>
<td>LNG inlet oC</td>
<td>°C</td>
<td>-160</td>
<td>-155</td>
<td>-130</td>
</tr>
<tr>
<td>LNG inlet density Kg/m³</td>
<td></td>
<td>455</td>
<td>453</td>
<td>417</td>
</tr>
<tr>
<td>Available inlet pressure Kg/cm²</td>
<td></td>
<td>14</td>
<td>14</td>
<td>14</td>
</tr>
<tr>
<td>Required discharge pressure Kg/cm²</td>
<td></td>
<td>76</td>
<td>76</td>
<td>76</td>
</tr>
<tr>
<td>Required discharge head m</td>
<td></td>
<td>1363</td>
<td>1368.6</td>
<td>1503</td>
</tr>
<tr>
<td>Resulting volumetric flow rate m³/h</td>
<td></td>
<td>290</td>
<td>287</td>
<td>195</td>
</tr>
<tr>
<td>Resulting mass flow rate t/h</td>
<td></td>
<td>132</td>
<td>130</td>
<td>80.4</td>
</tr>
<tr>
<td>Resulting pump efficiency %</td>
<td></td>
<td>68</td>
<td>68</td>
<td>63</td>
</tr>
</tbody>
</table>

The operating pressure in the recondensing heat exchanger will vary from 0.5 to 8.5 barg (as a design basis), depending on the operating conditions such as flow, temperature and compositions of re-gasified gas and enthalpy available in sub-cooled inlet LNG streams. The mixture is, then, sent to the boosting pumps which discharge the warmer and lighter LNG under flow control into the suction headers of high pressure (HP) pumps. One or two boosting pumps are running according to the send-out demand. The first role of a boosting pump is to compensate the low suction pressure of secondary pumps due to the operating pressure of re-liquefaction system. The design suction pressure of secondary pump is 14 barg. However, the operating pressure of the re-liquefaction system is limited as 8 barg owing to the vapor pressure (from BOG compressors and cold energy utilization plant). In addition, the boosting pumps also compensate the barometric head of the secondary pump, which requires a relatively higher head than a design case. This caused a revision in the actual operating philosophy of the terminal.

As the re-liquefaction system is a key facility installed in both LP and HP delivery systems, all operation conditions and alarms related to the system are reported to the Central Control Room. A staged shutdown system has been developed in order to get safe and highly reliable operation for both the vapor re-liquefaction system and the gas send-out system. The following concerns, sorted from the highest priority to the lowest, are taken into consideration in designing operation modes.

1. Safety of people and environment
2. Equipment safety
3. Continuous HP gas delivery
4. Continuous vapor re-liquefaction

The process shutdown of the re-liquefaction system has a vital role to ensure the safety in the case of some unexpected event, which may have an adverse effect on safe operation. The safety sequence shall stop the running boosting pumps, isolate the LNG inventory of the buffer compartment, and close the main inlet and outlet headers when abnormal operation conditions are detected.

Sendout Pressure Control

The terminal is one of base load terminals of KOGAS. In order to ensure the supply of NG to the clients, a loop type supply network, which covers the whole country, was constructed. Sendout pressure is either controlled by the terminal control room or by the Central Control Center (CCC) remotely. However, overall national network pressure and supply volume control is instructed by the CCC. The overall operation information, including the sendout rate with delivered pressure at each terminal and network nodes pressure and supply volume, is centralized for an effective gas supply and production system control.

The important role of the CCC is to ensure the stabilized NG supply by controlling the amount of gas regasification of each LNG terminal based on the gas demand estimation. The CCC focuses on controlling gas volume to be supplied than the pressure because the pressure control is a less significant parameter if the reserved supply volume is enough. Gas demand varies depending on Social Factors: public activity, weekend and holiday, and Natural Factors: ambient temperature. Even though it is quite a difficult to precisely estimate the gas demand, the inter-relationship between factors that affect gas demand provides proportionality and systematic regularity in factors. By this parameter analysis methodology, the gas demand is estimated, which is the basis of controlling daily supply and production of each terminal.

The analysis of the relationship between meteorological data and gas demand may have an inevitable error because of the uncertainty of meteorological estimation. The economic regasification
model of each terminal is provided by a production control system. The CCC decides to increase or decrease the amount of regasification of each terminal after it evaluates current regasification volume deviated from the gas demands. The economic regasification modes will be determined by evaluating terminal operating conditions such as current sendout rate, extra vaporization capacity, seawater temperature, and backup vaporizers’ capacity.

**LNG Unloading**

In order to minimize BOG in an intermittent cool down of the unloading lines, continuous cooling was achieved by LP LNG circulation. Following ship berthing and cool-down of the unloading arms, LNG is transferred to the onshore LNG tanks by the ship pumps. The unloading facilities have been designed to safely accommodate a wide range of carrier sizes from 87,000 m³ to 138,000 m³. The liquid unloading rate from the ship is usually 10,000 – 12,000 m³/hr carried out by 8 -10 pumps. It takes approximately 12 hours to unload one 135,000 m³ ship. From a ship, the LNG flows through the unloading arms and the unloading lines into the storage tanks.

The quantity of vapor in the tank outlet increases significantly during ship unloading. These additional vapors are a combination of volume displaced in the tanks by the incoming LNG, vapor resulting from the pumping energy in the ship, flash vapor due to the pressure difference between the ship and the storage tanks, and vaporization from heat leaks through the unloading arms and transfer lines. During ship unloading some of the vapor generated in the storage tank is returned to the ship's cargo tanks via the vapor return line and arm in order to maintain a positive pressure in the ship. Due to the low pressure difference between the storage tank and the ship, vapor return blowers are sometimes needed.

However, an extensive study for the terminal design improvement clearly showed that enough operating pressure of the LNG storage tank is available to return vapor without using vapor return blowers. The engineering calculation performed in the original design seemed to have a high design margin. When the second berth was designed, the low temperature-pressure thermodynamic data, including frictional pressure loss data obtained from the actual operation, were used in the BOG return line design. The return gas blowers, which were installed at the original construction, have been relocated to the second LNG terminal, Incheon Terminal, of the company.

Unloading was performed on one or two LNG tanks with the initial design. The stored LNG was then continuous circulated by a kick-back line in order to avoid any LNG stratification. LNG import sources have been diversified with an increase in gas demand. This means the LNG compositions, as well as its arrival temperature, are different from source to source. In order to avoid any possible roll over phenomenon, special care has been taken in controlling temperature differences, as well as calorific values. The allowable temperature difference inside the tank has been controlled within 1.5 °C. Moreover, the temperature and pressure differences between tanks were also controlled within 4 g/cm²g difference (normal operation pressure of storage tanks are 50 – 170 g/cm²g). One or two LNG Tanks have to standby to receive LNG with the initial design, which had to be depressurized in advance by using BOG compressors in order to avoid a sudden increase in operating pressure due to the massive flash gas. Figure 7 presents the LNG tank operating pressure profile during single or double tank unloading. Tank operating pressure has to be reduced to 150 g/cm²g by putting an additional BOG compressor.

By expansion of the terminal, LNG storage tanks have been added to 10 tanks from 4 tanks. This operating pattern has been changed for the even distribution of unloaded LNG to the several LNG tanks (up to 10 tanks). Then, the depressurizing process can be eliminated. The advantages of equal distribution are to prevent rollover, get easy pressure control of storage tanks, and secure safe operation. This allows distribution of LNG evenly into several tanks. As a result, the temperature of the stored LNG and pressure of the tanks can be easily controlled. Moreover, the calorific value of the regasified LNG can be controlled with the allowable operating margin, resulting in a high gas sendout quality.

An additional unloading berth was added to increase the terminal’s LNG receiving capacity in 1998. KOGAS is well-known as the biggest importer all over the World from a spot market in order to meet winter gas demand. These two berths allow a simultaneous unloading of LNG to storage tanks and mitigate the congestions of ship unloading. Both the unloading lines have been kept in cool-down by continuous circulation of LP LNG sent out from in-tank pumps. One of the design features of the multi-unloading facility is secure and safe unloading. Even with the operation case of an emergency shut down (ESD) valve or severe problem on neighboring unloading facility, the dynamic pressure effect of unloading lines is not hurt on the other unloading system. As a result, LNG unloading can be
done under any severe circumstance. Moreover, this double berth system allows several LNG cargos, of which the destination is either Incheon or Tongyoung terminal, to detour to unload their cargo when the weather conditions are not suitable for continuous voyage.

![Typical LNG tank operating pressure profile during unloading](image)

**Fig. 7 – Typical LNG tank operating pressure profile during unloading**

**Hot Working and Tie-in Procedure**

Ensuring the safe operation of the terminal, the effective expansion construction was placed at the first place during more than 12 years’ of expansion. Constructability of expansion work is generally considered less than the independent project because of a limitation of access and mobility. Safe work control is extremely important in both the operation of an existing terminal and expansion construction. In order to achieve it, as well as to ensure high constructability, the company established its unique safe work procedure including a tie-in procedure ensuring the safety operation during the hot work near the operating LNG facility.

The procedure requires providing a separate access road and fence in order to avoid general workers to access the operational facilities without permission and supervision. After expansion work had been done, it was required to tie-in between expanded facility and operating facility. Ensuring safety in tie-in work was the top priority. Uninterruption of the existing terminal operation was also emphasized. The details of hot working procedure are illustrated in Fig. 8.

A work scope has to be defined in the work definition stage so that the worker will do the confined work only. This eliminates the unnecessary work and enhances safe operation of an existing facility. Work procedure has to be prepared and submitted to the Safety Review Committee. The committee reviews the appropriateness of working procedures and safety plans. The details involve process review, work scope, impact of gas sendout, and safety achievement methodology. Once the work procedure is approved by the committee, the superintendent will supervise the work at the designated working date.

The normal tie-in procedure is also discussed in execution in Fig. 8. It requires blocking the designated section. Sometimes a small cryogenic valve is found leaking. Then the blocking section has to be redefined. The selected block has to be warmed up. The blocked section has to be inerted by nitrogen. Before the tie-in work, the Safety Enforcement Team checks the working conditions in order to ensure the hot working. It includes general working conditions, safety devices, fire fighting
devices, and methane contents. The superintendent allows the hot work if the methane density is less than 10% of Level of Explosion Level (LEL).

As the tie-in point cannot be tested by hydrostatic pressure or pneumatic closure test, it is strictly required to be the first grade of non-destructive examine on welding area. In order to avoid any pocket of mixed gas with air, nitrogen is injected again for inerting the section blocked. The nitrogen should be injected with the same direction of LNG or gas flow. The dew point of the section blocked is measured and the acceptance criterion is -50 °C. Gradual cool-down is then applied on the tie in section. The normal cool-down grade is 10 - 15 °C/hr. Pressure equalization is also applied if the block section is a high pressure line.

LNG TERMINAL OPERATION RELIABILITY

Definition of Reliability, Availability, and Risk

There is often confusion between the terms Reliability, Availability, and Risk. So far it has been seen that there is a need for a scientific definition of reliability and for a method of reliability evaluation which can be applied to a wide range of technological projects. Reliability related to the overall LNG terminal can be defined as the probability that the terminal as designed will perform its function (unloading LNG/storage/regasification) over a specified period of time under normal operating conditions. Similarly, the availability of an LNG terminal is the fraction of time that it can perform its function under normal operating conditions. On the other hand, a dictionary definition of risk is “the possibility of loss or injury to people and property”. Henley and Kumamoto5 defines the risk as follows:

\[
\text{Risk} = \text{Frequency} \times \text{Magnitude} \times \text{Events} = \text{Consequence} \times \text{Time} \times \text{Unittime} \times \text{Event} \]

(3)

The time a given system/equipment/unit operates before a failure is a random variable. Similarly, the time to repair the system/equipment/unit may follow a random distribution equal to the time to failure. If the probability density function, \( F_f(t) \), and the distribution of time-to-repair function, \( F_r(t) \), describe random variables, then the mean time-to-failure (MTTF) and the mean time-to-repair (MTTR) are found as follows:

\[
\text{MTTF} = \int_0^\infty F_f(t) \, dt \]

\[
\text{MTTR} = \int_0^\infty F_r(t) \, dt
\]
Green and Bourne\textsuperscript{6} addressed that after a relative short time of operation the probability of satisfactory operation for a given system/equipment approaches a constant value. This value defines the unit availability (AT) of the system and is given by:

\[ AT = \frac{MTTF}{MTTF + MTTR} \]  \hspace{1cm} (6)

The above Eq. 6 does not reflect the stand-by time of equipment. Some of equipment is available but not operating due to the difference between regasification facility capacity and gas demand assigned to the terminal. In order to compensate the stand-by time in the estimation of unit equipment availability, a new unit equipment availability is proposed as follows:

\[ AT = \frac{MTTF + ST}{MTTF + MTTR + ST} \]  \hspace{1cm} (7)

Existing data sources do not provide enough information on time dependent failure rates and consequently, time independent failure rates (exponential distributions) are used for most purposes.\textsuperscript{7} Besides, the assumption of a constant failure rate is normally reasonable for systems where the start-up failures are eliminated by good quality control and if the wear-out phase is avoided by good maintenance procedures (typical situation in LNG facilities).\textsuperscript{8} The assumption is very useful when there is insufficient data (i.e., process plant data) or when, for simplicity, a single parameter regression is to be used. One important feature of the constant failure rates is that sample sizes and run lengths can be of any size. For instance, data from 100 units running for 10 days is equivalent to data obtained from 10 units running for 100 days.\textsuperscript{8}

If the failure rates or success rates of the different systems/equipment of an LNG plant are known, then the plant unavailability or availability can be calculated by several methods such as Fault Tree Analysis, Reliability Block Diagrams, Failure Mode and Effect Analysis (FMEA), etc. The first two methods are most commonly used in the process industry. There are many computer programs available to do such analysis.\textsuperscript{6,9} In this study, the following conventional definition of the reliability is used:\textsuperscript{7}

\[ RT = \frac{TOT}{TOT + UT_f} \]  \hspace{1cm} (8)

where,

- \( RT \) : Equipment Reliability
- \( TOT \) : Total operating time of equipment
- \( UT_f \) : Unavailability time due to scheduled maintenance

**Equipment Reliability**

The sendout reliability of an LNG terminal is largely determined by the major equipment items included in the design. The equipment provided within the terminal can be categorized as follows in terms of contributions to overall reliability: Static equipment, intermittent operational equipment, and key regasification equipment.

Static equipment includes a flare knockout drum and instrument air receivers (vessels). These items are, in general, very reliable with very low failure rates (typically one failure per 100,000 operating hours), provided the design and fabrication is performed according to recognized codes and standards.\textsuperscript{8}

Intermittent operation equipment categorizes unloading arms and BOG compressors. Regardless of their reliability level, the ability to maintain sendout is unaffected. Unloading arm failures can be repaired between unloadings; otherwise the unloading can be completed through a
single arm over a longer period. Since several compressors are provided to handle excess displacement vapour during the ship unloading operation and a few are required to handle normal BOG, a spare machine normally exists, allowing repair between unloadings. Failure during unloading can be handled by reducing the unloading rate or by flaring excess vapour.

Key regasification equipment consists of pumps and vaporizers. These equipment items are provided with spare capacity so that full sendout can be maintained while one item is out of service. In order to permit full sendout flow in spite of an in-tank pump failure, the plant design assumes that three in-tank pumps will be running at reduced flow with any two pumps capable of ramping up to full flow. Since the ORV’s have no moving parts, they are essentially very reliable. They are, however, susceptible to surface fouling due to exposure to seawater. This fouling potential is controlled by dosing but periodically the units must be taken out of service for cleaning and painting. In order make up for this short fall the submerged combustion vaporizers (SCV’s) will be kept in a rolling standby mode such that it can rapidly respond to the increase in sendout.

Reliability Data Collection

The company developed the equipment history card system and has applied it from the startup operation of the terminal. It includes the equipment tag number, purchase date, installation date, operation history, and maintenance history. The actual operation records were analyzed to get an operation hour of main equipment of regasification. Each operation hours were then summed to the same equipment type. Since equipment capacity installed at the initial stage are different from those of expansion, operation records were separately collected for the different equipment size even with the same type. As the same token, the maintenance history records of each equipment have been investigated and collected based on the type of failure, including preventive (regular planned) maintenance.

Analysis of Reliability Data

The reliability data base, for the main regasification process units, was established based on 18 years of operation at the Pyeongtaek terminal. Table 2 presents the summarized reliability database.

<table>
<thead>
<tr>
<th>Process Unit</th>
<th>MTTF</th>
<th>MTTR</th>
<th>N</th>
<th>TOT</th>
<th>ST</th>
<th>RT (%)</th>
<th>AT (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Unloading Arm</td>
<td>3,835</td>
<td>55</td>
<td>8</td>
<td>69,030</td>
<td>31,150</td>
<td>98.59</td>
<td>99.84</td>
</tr>
<tr>
<td>In-tank Pump</td>
<td>3,221</td>
<td>400</td>
<td>22</td>
<td>698,957</td>
<td>5,139</td>
<td>88.95</td>
<td>95.43</td>
</tr>
<tr>
<td>Booster Pump</td>
<td>4,277</td>
<td>435</td>
<td>20</td>
<td>996,541</td>
<td>4,048</td>
<td>90.77</td>
<td>95.03</td>
</tr>
<tr>
<td>BOG Comp.</td>
<td>5,103</td>
<td>70</td>
<td>6</td>
<td>336,765</td>
<td>3,588</td>
<td>98.66</td>
<td>99.21</td>
</tr>
<tr>
<td>ORV (A type)</td>
<td>3,288</td>
<td>60</td>
<td>2</td>
<td>105,216</td>
<td>5,412</td>
<td>98.21</td>
<td>99.32</td>
</tr>
<tr>
<td>ORV (S type)</td>
<td>7,012</td>
<td>60</td>
<td>7</td>
<td>273,468</td>
<td>1,688</td>
<td>99.15</td>
<td>99.32</td>
</tr>
<tr>
<td>SCV</td>
<td>346</td>
<td>48</td>
<td>6</td>
<td>19,376</td>
<td>8,366</td>
<td>87.82</td>
<td>99.45</td>
</tr>
</tbody>
</table>

Note: These are operational data recorded from 1986 to 2002.

LNG Unloading Arms

Operation records of vapor return does not separate from LNG unloading arms in this study. Three 16" LNG unloading arms, and one vapor return arm have been used for 18 years in the first berth. The first overhaul for LNG arms was performed after 4 years of operation. The same size equipment has been installed at the second berth, which have been operated for years. A MMTF of 3,835 hours was obtained from two (2) berths. This value equates to approximately 310 deliveries of LNG. LNG unloading arms and vapor return arm have intermittently operated.

LNG Storage in-tank pumps

At the initial design of the terminal, two LNG in-tank pumps were installed. Three LNG tanks were dedicated for the initial operation in 1986. One year later the fourth LNG tank was added. By the consecutive expansion, ten LNG tanks (above-ground membrane type tank), of which capacity is 100,000 m³ each, are under operation. A total of 22 LNG in-tank pumps have been operated. An MTTF of 3,221 hours was obtained. This value is lower than the MTTF values reported by GIIGNL (6100 hrs) and by...
GRI7 (3900 hrs). The GRI study is based on US plants which are mainly peak shaving plants, where pumps would be largely used intermittently.

**LNG Booster Pumps**

A total of six units of high booster pumps, of which capacity is 80 t/h, have been operated since the terminal started its operation. Different capacity (110 t/h) of LNG booster pumps has been installed at the expansion stage. A total of 20 units of LNG pumps are under operation.

**BOG Compressors**

Three horizontal double stage BOG compressors and three vertical double stages, non-contacted type Labyrinth, have been operated. At the initial operation stage, frequent shut down and minor failures were found. Accumulated operation experience and the reliable maintenance technology reduced the maintenance period and failure frequencies. An MTTF of 5,103 hours was obtained.

**Open Rack Type Vaporizers (ORV’s)**

Two different pressure rating ORV’s have been used: high pressure (HP) ORV’s and low pressure (LP) ORV’s. LP ORV’s were installed to re-gasify LNG for an adjacent thermal power plant. Two different types of HP ORV’s have been operated: top reserve type design (AL type) and trough type (SP type). 3,288 hours and 7,012 hours of MTTF have been obtained for AL type and SP type, respectively. The difference can be interpreted as manufacturing reliability, which is also an important parameter in unit equipment reliability as well as terminal availability.

**Submerged Combustion Vaporizers (SCV’s)**

An MTTF of 346 hours was obtained which is lower than the GRI study report10 which gives an MTTF of 3300 hours. The SCV’s have mainly operated for peak shaving and back-up facility. The SCV’s operation is a typical intermittent operation.

**Availability Estimation of LNG Terminal**

The unit equipment reliability may be different from that of the sendout system because the sendout system consists of several types of equipment. These involve key main equipment discussed in this study. However, the sendout system is simplified consisting of storage LP in-tank pumps, HP boosting pumps, and ORV’s. Seawater pumps and SCV’s are excluded in this estimation. Terminal sendout operation availability can be useful guideline to determine the level of back-up facility.

The example availability calculations below are based on a terminal with 5 Mt/a LNG throughput a peak sendout of 870 t/h (about 1 bcf/d). The following process line-ups have been considered:

- Common header between LP in-tank pumps and HP pumps
- Common header between HP pumps and ORV’s

LNG input volume of each LP in-tank pump into LP header is assumed to be the same. All HP pumps are connected to the same header with feeds the 6 ORV’s. The flow in the common header has to be distributed equally in the ORV, by adjusting flow control valve set points upstream the vaporizers. Sendout line-ups are described in Table 3.

**Table 3 – Sendout Line-ups (Example calculation)**

<table>
<thead>
<tr>
<th>Equipment</th>
<th>No of Unit</th>
<th>Unit capacity (t/h)</th>
<th>Total capacity (t/h)</th>
</tr>
</thead>
<tbody>
<tr>
<td>LP in-tank pumps</td>
<td>10</td>
<td>150</td>
<td>1500</td>
</tr>
<tr>
<td>HP Pumps</td>
<td>10</td>
<td>110</td>
<td>1100</td>
</tr>
<tr>
<td>ORVs</td>
<td>6</td>
<td>180</td>
<td>1080</td>
</tr>
</tbody>
</table>

The calculated availability of each system is as follows (Refer to Tables 4 – 6):

- LP in-tank pump system : 93.53%
- HP boost pump system : 91.64%
- ORVs : 99.93 %
### Table 4 – Availability of LP Pump System

<table>
<thead>
<tr>
<th>Case</th>
<th>#1</th>
<th>#2</th>
<th>#3</th>
<th>#4</th>
<th>Others</th>
<th>% flow rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>O</td>
<td>O</td>
<td>O</td>
<td>O</td>
<td>O</td>
<td>172</td>
</tr>
<tr>
<td>2</td>
<td>x</td>
<td>O</td>
<td>O</td>
<td>O</td>
<td>O</td>
<td>155</td>
</tr>
<tr>
<td>3</td>
<td>x</td>
<td>x</td>
<td>O</td>
<td>O</td>
<td>O</td>
<td>138</td>
</tr>
<tr>
<td>4</td>
<td>x</td>
<td>x</td>
<td>x</td>
<td>O</td>
<td>O</td>
<td>121</td>
</tr>
<tr>
<td>5</td>
<td>x</td>
<td>x</td>
<td>x</td>
<td>x</td>
<td>O</td>
<td>103</td>
</tr>
</tbody>
</table>

Availability of LP pump system

\[
(\text{AT})_{\text{LP}} = (0.9543)^6 + (0.9543)^5 \times (1-0.9543) + (0.9543)^4 \times (1-0.9543)^2 + (0.9543)^3 \times (1-0.9543)^3 + (0.9543)^2 \times (1-0.9543)^4 + (0.9543) \times (1-0.9543)^5 + (1-0.9543)^6 = 0.9353
\]

Note: X: equipment is stopped, O: equipment is running

### Table 5 – Availability of HP Pump System

<table>
<thead>
<tr>
<th>Case</th>
<th>#1</th>
<th>#2</th>
<th>#3</th>
<th>Others</th>
<th>% flow rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>O</td>
<td>O</td>
<td>O</td>
<td>O</td>
<td>172</td>
</tr>
<tr>
<td>2</td>
<td>x</td>
<td>O</td>
<td>O</td>
<td>O</td>
<td>155</td>
</tr>
<tr>
<td>3</td>
<td>x</td>
<td>x</td>
<td>O</td>
<td>O</td>
<td>138</td>
</tr>
<tr>
<td>4</td>
<td>x</td>
<td>x</td>
<td>x</td>
<td>O</td>
<td>121</td>
</tr>
</tbody>
</table>

Availability of HP pump system

\[
(\text{AT})_{\text{HP}} = (0.9503)^6 + (0.9503)^5 \times (1-0.9503) + (0.9503)^4 \times (1-0.9503)^2 + (0.9503)^3 \times (1-0.9503)^3 + (0.9503)^2 \times (1-0.9503)^4 + (0.9503) \times (1-0.9503)^5 + (1-0.9503)^6 = 0.9164
\]

### Table 6 – Availability of ORV System

<table>
<thead>
<tr>
<th>Case</th>
<th>#1</th>
<th>#2</th>
<th>Others</th>
<th>% flow rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>O</td>
<td>O</td>
<td>O</td>
<td>172</td>
</tr>
<tr>
<td>2</td>
<td>x</td>
<td>O</td>
<td>O</td>
<td>155</td>
</tr>
<tr>
<td>3</td>
<td>x</td>
<td>x</td>
<td>O</td>
<td>138</td>
</tr>
<tr>
<td>4</td>
<td>x</td>
<td>x</td>
<td>O</td>
<td>121</td>
</tr>
</tbody>
</table>

Availability of ORV system

\[
(\text{AT})_{\text{ORV}} = (0.9932)^6 + (0.9932)^5 \times (1-0.9932) + (0.9932)^4 \times (1-0.9932)^2 + (0.9932)^3 \times (1-0.9932)^3 + (0.9932)^2 \times (1-0.9932)^4 + (0.9932) \times (1-0.9932)^5 + (1-0.9932)^6 = 0.9993
\]

The terminal sendout availability with a common header between pumps and ORVs are 85.65%. \((0.9353 \times 0.9164 \times 0.9993 = 0.8565)\). This sendout availability data can be useful to determine the level of backup facility. This is the availability during peak sendout 1 bscfd, and the availability during normal sendout is likely 100%. The frequency of peak sendout and project economics should be considered in determination of the level of back-up facility.

### CONCLUSIONS

1. Re-condensing type of vapor re-liquefaction system has a high operational reliability. The reliable operation has been achieved by maintaining the minimum LNG sendout flow.

2. The consideration of vapor treatment system in LNG terminal and the initial plan of cold energy utilization can provide a more reliable system operation, as well as higher economical benefits.

3. The terminal operators’ experience in the improvement of conventional design can be useful to the engineers in designing an LNG chain.

4. The newly proposed methodology to estimate the system availability is more reliable and realistic than the conventional method. The estimated terminal sendout availability is well represented with the approach of unit equipment reliability, availability of unit system, and whole system availability.

### RECOMMENDATIONS

The vapor cooling can dramatically reduce the requirement of supersaturated LNG that is minimum sendout volume. The pressurized LNG from secondary pumps (up to 76 Kg/cm²) can be used for vapor cooling because it is still supersaturated. Therefore, it is recommended installation of...
high-pressure heat exchangers for vapor cooling using a direct or an indirect heat exchange in order to get a stable operation during a low sendout flow rate.

**NOMENCLATURES and ABBREVIATIONS**

\[ \Delta P_s : \text{super saturated pressure} \]
\[ \frac{dT}{dP} : \text{average rate of change in saturation temperature in liquid with pressure} \]
\[ \Delta T_s : \text{total temperature difference between liquid and surface} \]
\[ m_{BOG} : \text{BOG mass rate} \]
\[ MTTF : \text{mean time to failure} \]
\[ MTTR : \text{mean time to repair} \]
\[ N : \text{number of units} \]
\[ TOT : \text{total operation hours} \]
\[ ST : \text{stand-by time} \]
\[ RT : \text{reliability of unit equipment} \]
\[ AT : \text{reliability of equipment} \]

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**REFERENCES**