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Dynamic simulation of LNG loading, BOG generation, and BOG recovery at LNG exporting terminals

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ABSTRACT

Liquefied natural gas (LNG) is a prominent clean energy source available in abundance. LNG has high calorific value, while lower price and emissions. Vapors generated from LNG due to heat leak and operating-condition-changes are called boil-off gas (BOG). Because of the very dynamic in nature, the rate of BOG generation during LNG loading (jetty BOG, or JBOG) changes significantly with the loading time, which has not been well studied yet. In this work, the LNG vessel loading process is dynamically simulated to obtain JBOG generation profiles. The effect of various parameters including holding-mode heat leak, initial-temperature of LNG ship-tank, JBOG compressor capacity, and maximum cooling-rate for ship-tank, on JBOG profile is studied. Understanding JBOG generation would help in designing and retrofitting BOG recovery facilities in an efficient way. Also, several JBOG utilization strategies are discussed in this work. The study would help proper handling of BOG problems in terms of minimizing flaring at LNG exporting terminals, and thus reducing waste, saving energy, and protecting surrounding environments.

1. Introduction

The global production capacity of liquefied natural gas (LNG) is expanding very fast. Actually, LNG is becoming the fastest increasing energy sector due to the rapid growth in world-wide clean energy demands. The U.S. Energy Information Administration (EIA) indicates that the world natural gas trade will be poised to increase tremendously in the future by both pipeline and shipment in the form of LNG (Barden and Ford, 2013). About 285 million tons per year (MTPA) of liquefaction capacity has been proposed in North America alone (Ferrier, 2014). New LNG terminals, which are currently under construction, will increase the LNG production by 125 MTPA (Conti, 2014). In 2014 only, over 297 MTPA world-wide LNG operating capacity was recorded (World Gas Conference, 2015).

LNG takes about 600 times smaller space as compared to natural gas of the same mass. Natural gas mainly contains methane, and requires very low temperatures (below −160 °C) in order to liquefy near atmospheric pressure. Vapors are generated from LNG due to slow boiling and other factors. These vapors are called boil-off gas (BOG). BOG generation is caused by several factors: (1) depressurization of LNG (flashing); (2) heat added by equipment like pumps; (3) tank breathing or vapor displacement; (4) environmental heat leaks through containers and pipelines; and (5) LNG carrying vessels being relatively hot while loading LNG. Heat leak from environment into LNG occurs continuously since there is always difference in temperature of ambient and temperature of LNG. The heat leak from hotter tank into LNG is due to heat content of the metal of the tank, which vanishes once thermal equilibrium state is achieved between the metal and LNG.

Three main BOG generation locations are identified at LNG exporting terminals: (1) Flash Tank after the main cryogenic heat exchanger (MCHE), (2) Storage-Tanks, and (3) Jetty. BOG from the

Abbreviations: BOG, Boil-off gas; C3, Propane; C3-MR, Propane-and-Mixed-Refrigerant (Natural Gas Liquefaction Process); FBOG, Boil-off Gas from depressurization of LNG after MCHE; FBOG2, Boil-off Gas from depressurization of liquefied BOG; FL, BOG generated due to depressurization (flashing) of inlet stream; GHG, Greenhouse Gas; HE, BOG generated due to heat added by equipment like pumps; HL, BOG generated due to heat leak from surrounding into container/pipeline; HT, BOG generated due to hot tank/container; JBOG, Boil-off gas from jetty (while loading a Cargo); LIN, Liquid nitrogen; LNG, Liquefied natural gas; MCXB, Main cryogenic heat exchanger bottom section; MCHE, Main cryogenic heat exchanger (MCXB and MCXT); MCXT, Main cryogenic heat exchanger top section; MR, Mixed refrigerant; MTPA, Million Tonnes Per Annum; N_2, Nitrogen; NG, Natural gas; NRU, Nitrogen removal unit used for LNG; NRU2, Nitrogen removal unit used for BOG; PI, 'Proportional, Integral' type of process controller; TBOG, Boil-off Gas from LNG storage tanks; VD, BOG generated due to vapor displacement caused by inlet stream; VRA, Vapor return arm.

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Flash Tank after MCHE (named as 'FBOG') is due to flashing of high pressure LNG from MCHX to storage pressure i.e. due to BOG-generation-factor 1. BOG from Storage-Tanks (named as 'TBOG') is due to factor 1, 2, 3, and 4. BOG from jetty (named as 'JBOG') is generated during LNG ship loading, and is due to all of five factors listed above. JBOG generation is very dynamic in nature with respect to process conditions and also varies with LNG loading time. In several literatures steady-state behavior of BOG generation and recovery has been explained; however, dynamic behavior of BOG generation, especially JBOG generation, remains unexplained.

LNG industries are actually facing BOG problems in different sectors of the LNG supply chain (Dobrota et al., 2013): during LNG production, storage, loading, transportation, unloading processes, and regasification processes. BOG generation and its handling during transportation has been addressed in many literatures including the following (Shin and Lee, 2009; Sayyaadi and Babaelahi, 2010; Pil et al., 2008; Romero Gómez et al., 2015; Bahgat, 2015; Hasan et al., 2009). Shin and Lee utilized Microsoft® Visual C++6.0 object-oriented programming along with REFPROP® 7.0 thermodynamic property calculator for dynamic simulation of BOG re-liquefaction process on LNG carriers (Shin and Lee, 2009). Sayyaadi and Babaelahi worked on thermoeconomic optimization of such re-liquefaction processes (Sayyaadi and Babaelahi, 2010). Pil, Chang Kwang et al. performed reliability assessment of these re-liquefaction systems on LNG carriers (Pil et al., 2008). Gómez, J. Romero et al. utilized Engineering-Equation-Solver program to model BOG re-liquefaction on LNG carriers; and optimized the process to increase energy and exergy efficiencies of cascade refrigeration cycle used for BOG re-liquefaction, by recovering cold energy from BOG (Romero Gómez et al., 2015). Bahgat, Walid M proposed storage of BOG as pressurized-LNG at higher temperature and pressure as compared to LNG, claiming decrease in energy required for re-liquefaction of BOG (Bahgat, 2015). Hasan, M. M. F et al. performed dynamic simulation of LNG transportation in Aspen HYSYS process simulation software using Soave-Redlich-Kwong (SRK) equation of state property method, focusing on minimization of BOG generated during LNG transportation (Hasan et al., 2009).

BOG generation and its handling at LNG regasification/receiving/importing terminals and during LNG ship unloading has been addressed in many literatures including the following (Liu et al., 2010; Park et al., 2012; Rao et al., 2016; Zolfkhani, 2013; Li et al., 2012; Li and Li, 2016; Wang et al., 2013; Wang and Xu, 2014; Jang et al., 2011; Shin et al., 2008). Liu, Chaowei et al. studied thermodynamic-analysis-based design and operation of BOG recovery at LNG receiving terminals, in order to minimize flaring and total energy consumption (Liu et al., 2010). For LNG regasification and distribution, heat is added to LNG to evaporate it. Some heat from BOG can be transferred to LNG by direct mixing of BOG with LNG, where portion of BOG is liquefied. Since liquid compression requires significantly less energy as compared to vapor compression, liquefying BOG by mixing with LNG resulted in energy savings in achieving pipeline pressure of 70 bar for BOG and evaporated LNG. Based on similar method of mixing BOG and LNG, Park, Chansaem et al. proposed retrofit design for LNG regasification process at LNG receiving terminals so as to reduce operating cost and increase energy savings by using LNG cold energy in intercoolers between compressors (Park et al., 2012). Rao, Harsha N. et al. claimed minimum total energy requirements for BOG recovery and LNG regasification at LNG receiving terminals by first pre-cooling BOG using LNG, and then recompressing the BOG, inter-cooling it using LNG, and re-condensing it by direct mixing with LNG in two stages (Rao et al., 2016). Zolfkhani, M. worked on finding optimum pressure for re-condensation of BOG generated during normal operation case and LNG unloading case; in order to minimize operating cost as well as flaring at regasification terminals (Zolfkhani, 2013). Li, Yajun et al. worked on optimization of such BOG re-condensation process and provided process control strategy for operational stability and reliability (Li et al., 2012). Li, Yajun et. al., in another publication, worked on dynamic optimization to deal with fluctuations in BOG generation at LNG receiving terminals during LNG ship unloading (Li and Li, 2016). Wang, M. et al. worked on integrating shale gas NGL recovery and LNG regasification processes for maximum energy savings (Wang et al., 2013; Wang and Xu, 2014). Jang, N. et al. proposed an algorithm for the optimal operation of a BOG compressor at an LNG gasification plant (Jang et al., 2011). Shin, M. W. et al. proposed boil-off-rate model in order to predict pressure changes in LNG storage tanks at LNG receiving terminals and thus to have a safe and energy-saving BOG compressor operation (Shin et al., 2008).

BOG generation in natural gas liquefaction plant and at LNG exporting/loading terminals has been discussed in some publications (Huang et al., 2009, 2007; Kurle et al., 2015; Chaker et al., 2014; Wicaksono et al., 2007; Pillai et al., 2013). However, dynamic simulation study of BOG generation at LNG exporting terminals has not been performed yet. Huang, S. et al. provided methods to simulate LNG related systems and suggested use of end-flash-gas as fuel gas to run turbines in LNG plant (Huang et al., 2009). Huang, S. et. al., in another publication, provided various BOG recovery strategies at LNG loading terminals, particularly for long jetties which tend to generate more JBOG due to greater heat leaks (Huang et al., 2007). BOG generation at LNG exporting terminals is studied by the authors in previous work using steady-state simulations; where heat leak calculations are performed and various strategies to recover the BOG are simulated using Aspen Plus software (Kurle et al., 2015). Chaker, M. et al. state that most publications in the past have focused on regasification terminals and have not addressed the area of liquefaction plants; thereby providing discussion on generation and management of BOG in LNG plant, and the associated networks and machinery to manage BOG handling (Chaker et al., 2014). Wicaksono, D. et al. studied efficient use of recovered jetty-BOG as fuel gas using mixed-integer-nonlinear-programming for fuel-gas-network (Wicaksono et al., 2007). Pillai, Pradeep et al. studied optimum design of BOG compressor network, and stated need for dynamic simulation of BOG system (Pillai et al., 2013).

It should be noted that the rate of JBOG generation during LNG loading changes with loading time. Thus, JBOG generation needs to be well studied so that it can be handled properly to avoid potential process upsets, flaring and wastage of material. Because of the dynamic nature of the LNG loading process, detailed dynamic simulations need to be employed to understand the insight of the process. Knowing JBOG generation rate with respect to loading time will help find effective and efficient JBOG recovery strategies. Roughly, BOG generations at exporting terminals range from 1% to over 3% of the produced LNG. If they were not recovered and reused, the total amount of material lost world-wide would be more than 3 MTPA.

With increasingly intensive global competitions and stricter environmental regulations, BOG flaring is becoming more unacceptable. Worldwide, LNG industry expansions are in progress. Therefore, BOG generation and recovery at LNG exporting terminals require special considerations so as to avoid air pollution and losses of energy and material. In this study, the LNG vessel loading process is dynamically simulated to obtain JBOG generation profiles and to study JBOG recovery strategies. Understanding Jetty BOG generation behavior would help in building Jetty BOG recovery processes like one recently built by Qatargas Operating Company Limited (Qatargas Operating Company Ltd, 2014; Hydrocarbons-technology.com). In order to understand how much BOG can be used as fuel gas in LNG plant, fuel requirements to run steam turbines and gas turbines for natural gas liquefaction in LNG plant are calculated. The study would help proper handling of BOG problems in terms of minimizing flaring at LNG exporting terminals, and

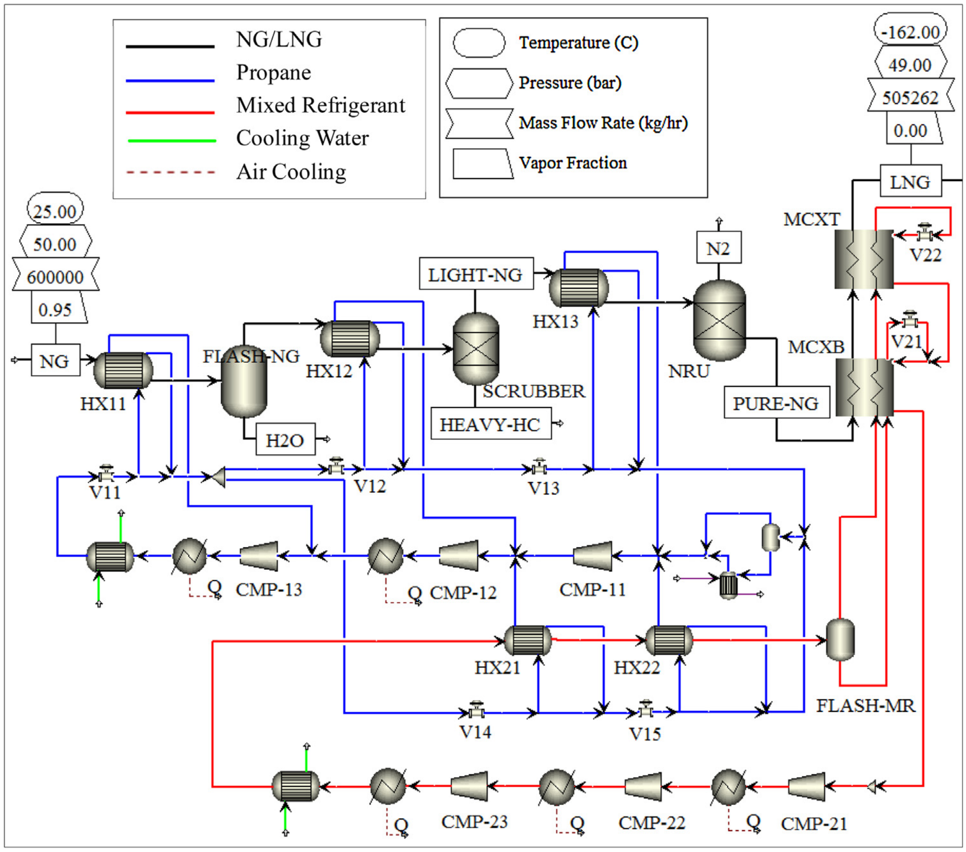

Fig. 1. Aspen steady-state process modeling schematic for LNG plant.

thus reducing waste, saving energy, and protecting surrounding environments.

2. Process modeling and model input preparation

In this study, Natural gas liquefaction, LNG storage facilities, and loading facilities are simulated to study BOG handling process at LNG exporting terminals. A typical Propane-and-Mixed-Refrigerant (C3-MR) process by Air Products and Chemicals Inc. (APCI) was used for liquefaction of natural gas. Natural gas feed flow rate is assumed to be 600,000 kg/h. The steady state process was simulated using Aspen Plus v8.8, and exported to Aspen Plus Dynamics v8.8 to study the dynamic behavior of LNG loading facility. Peng Robinson cubic equation of state with the Boston-Mathias alpha function (PR-BM) property method was used for the process simulation. The selection of the property method is based on suggestions by 'Aspen Property Method Selection Assistant' feature in Aspen Plus software. The process parameters for the liquefaction

Table 1
Composition of Natural Gas Feed Stream and LNG Product Stream.

	NG (Feed)		LNG (from MCHE)	
	Mass%	Mole%	Mass%	Mole%
Methane	80.0	87.48	92.83	96.21
Ethane	6.0	3.50	4.99	2.76
Propane	2.0	0.80	0.71	0.27
n-Butane	1.0	0.30	0.12	0.03
i-Butane	1.0	0.30	0.12	0.03
n-Pentane	0.5	0.12	0.05	0.01
i-Pentane	0.5	0.12	0.05	0.01
Nitrogen	4.0	2.50	1.13	0.67
Water	5.0	4.87	0.00	0.00

section were taken from article by Ravavarapu et al. (Ravavarapu et al., 1996). The following assumptions were made for the modeling:

1 Two 'above-ground full-containment' type LNG storage tanks, each with volume of 168,000 m^3, and 1.6:1 dimeter to height ratio
2 LNG ship with four Moss type spherical tanks with 1 m equatorial height, and total volume of 143,000 m^3
3 Long jetty with equivalent LNG-piping length of 6000 m (Huang et al., 2007), two LNG loading lines each of 24-inch diameter, with pipe frictional factor of 30 μm
4 One JBOG return pipeline of 24-inch diameter and pipe frictional factor of 45 μm with 6000 m equivalent length up to LNG storage area

Fig. 1 shows the studied natural gas liquefaction process. Sweet natural gas feed is considered as starting point for the simulation, with flow rate of 600,000 kg/h at 25 °C and 50 bar. The composition of natural gas feed stream and the resulting LNG stream is given in Table 1. Water, heavy hydrocarbons, and nitrogen are removed from the natural gas stream, and it is precooled to −34 °C using propane refrigerant. The natural gas is liquefied in main cryogenic heat exchanger using mixed refrigerant (MR). The main cryogenic heat exchanger (MCHE) comprises bottom section (MCXB) and top section (MCXT). The mixed-refrigerant with composition of methane 40%, ethane 35%, propane 15%, and nitrogen 10% by mole, is precooled to −34 °C using propane refrigerant. The mixed-refrigerant stream is then flashed and separated into heavy-component-stream and light-component-stream. The heavy-component-stream is used to cool natural gas to about −112 °C in lower/bottom section of main cryogenic heat exchanger (MCXB). The light-component-stream is used to sub-cool natu-

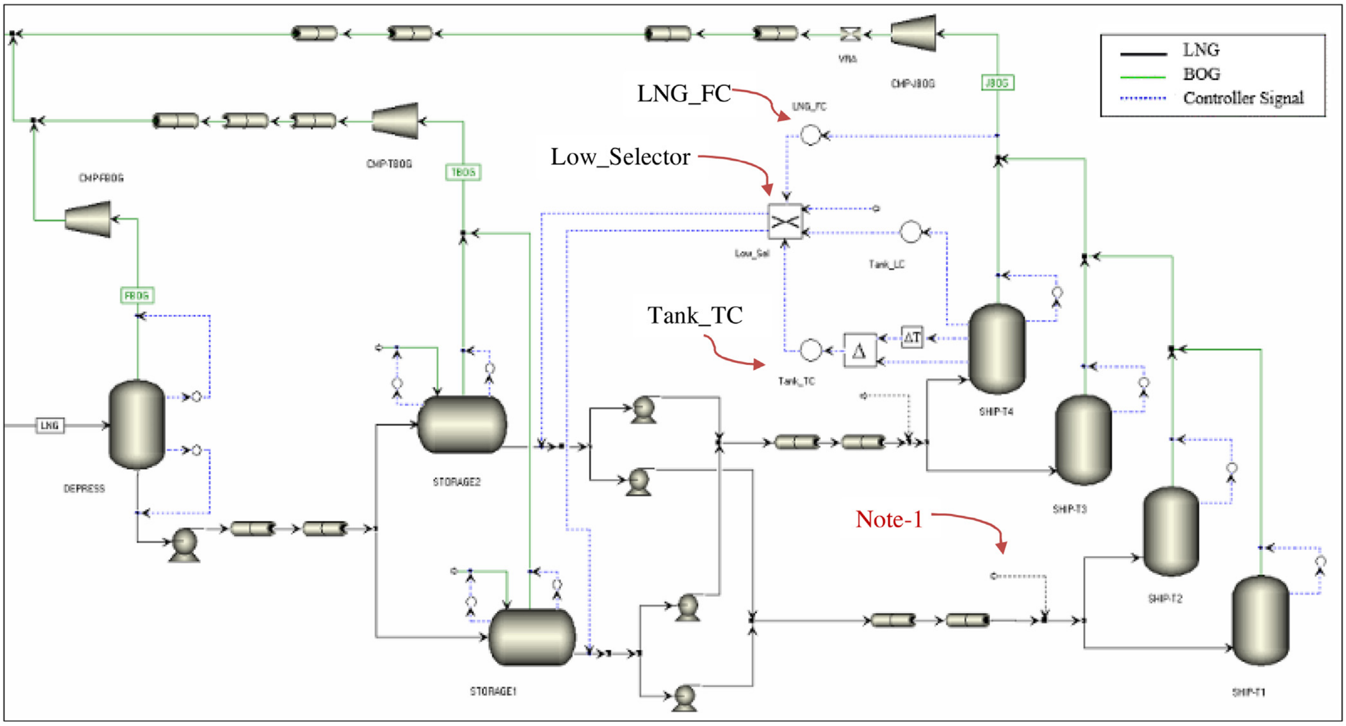

Fig. 2. Aspen dynamic process modeling schematic for LNG storage facility, loading facility, ship tanks, and BOG handling facility.

ral gas to −162 °C in upper/top section of main cryogenic heat exchanger (MCXT). The amount of LNG produced at the outlet of MCXT (or MCHE) is about 1022 m^3/h (about 505,000 kg/h). Excluding FBOG and TBOG, LNG in-storage-tank production rate is about 1010 m^3/h. Considering average operating period for the plant as 355 days per year, the plant capacity is about 4.2 MTPA.

Fig. 2 shows the LNG storage area, LNG loading facility, and an LNG carrier at exporting terminal. Sub-cooled LNG stream from MCHX is flashed to storage pressure of 1.06 bar. Flashing removes some amount of nitrogen and methane from LNG. Then, LNG is sent to storage tanks. Two storage tanks with the capacity of 168,000 m^3 for each are used in the simulation. LNG is loaded from storage tanks to LNG ship tanks through two 24 inch pipelines. With the consideration of long jetty, equivalent length of each loading line is taken as 6000 m. LNG carrier with total volume of about 143,000 m^3, with four spherical tanks is considered. BOG generated from ship tanks is sent to the shore using a blower/compressor of outlet pressure of 2.5 bar. A 24-inch pipeline carries the BOG to shore, where it is combined with shore BOG (FBOG and TBOG) and compressed to 50 bar pressure.

2.1. Heat leak calculations

In order to study the BOG generation at LNG terminal, heat leak calculations for each of storage and loading units are necessary. Calculations for heat transfer due to conduction, convection, and radiation are explained in the previous work (Kurle et al., 2015). In this section, some additional calculations are given.

2.1.1. Heat leaks during holding mode

Since LNG loading is an intermittent process, the LNG loading facilities are in 'holding mode' when LNG is not being loaded to LNG ship/carrier. During the holding mode, there is heat leak from environment into the pipeline. This heat addition also needs to be considered in order to calculate JBOG generation correctly. The calculation of heat leak during holding mode is described below. The following two options are discussed about the holding mode: (1) LNG may be retained in the pipelines for the duration of holding mode, and (2) Loading lines may be emptied after every loading. For the first option, vapors generated due to heat leak must be relieved from the pipeline to avoid overpressure and unsafe conditions. And, for the second option, precooling of LNG pipelines will be necessary before each LNG-loading.

This paragraph describes the heat leak calculation for LNG being retained in pipelines during holding mode. For chosen plant capacity and operating days, LNG carrier of 140,000 m^3 LNG capacity (98% of actual tank volume (International Maritime Organization, 1994)) can be loaded 62 times a year. Duration of one loading cycle is about 138 h. Out of which approximately 18 h are needed for LNG loading. This means that the loading facility will be on 'holding mode' for about 120 h or 5 days. For longer loading duration, the holding mode duration will be less than 120 h. In order to calculate maximum heat leak during holding mode the maximum duration of holding time (120 h) is considered. For the two LNG loading lines of 24-inch diameter and 6000 m equivalent pipe length, the inner surface area is about 22,982 m^2. The overall heat transfer coefficient is taken as 0.26 W/(m^2K) (Kitzel, 2015). With ambient temperature of 15 °C, and LNG temperature of about −161 °C, maximum value for temperature gradient i.e. 176 °C is considered. Thus, the maximum heat leak through LNG piping for total duration of holding mode (120 h) is calculated to be 454 GJ. The volume of two LNG pipelines is about 3500 m^3, which will absorb heat leak of 454 GJ during holding mode. However, all the heat absorbed is not retained in LNG in the pipeline. Major part of the heat absorbed is utilized to evaporate LNG, and the vapor generated need to be relieved to maintain the pipeline pressure. Using a separate Aspen Dynamic simulation, in a flash tank with 3500 m^3 volume and 1,700,000 kg of LNG, 454 GJ of heat was added while maintaining the tank pressure. If pipeline pressure is maintained at 1.06 bar during holding mode, the resulting temperature of LNG is about −160.2 °C, and only 2.5 GJ heat is retained in liquid in pipelines. If pipeline pressure is maintained at 5 bar during holding mode, the resulting temperature of

Table 2
Mass% Composition of LNG Being Loaded and Heel in Ship-tanks.

	LNG (to LNG Carrier)	Heel (Liquid in Ship Tanks, just before LNG Loading)			
		−125 °C	−135 °C	−145 °C	−155 °C
Methane	93.00	4.82	8.27	16.07	41.08
Ethane	5.10	77.73	75.02	68.71	48.27
Propane	0.73	11.76	11.26	10.26	7.18
n-Butane	0.12	1.96	1.88	1.71	1.20
i-Butane	0.12	1.96	1.88	1.71	1.20
n-Pentane	0.05	0.88	0.85	0.77	0.54
i-Pentane	0.05	0.88	0.85	0.77	0.54
Nitrogen	0.81	0.00	0.00	0.00	0.00
Water	0.00	0.00	0.00	0.00	0.00

LNG is about −137 °C, and about 40 GJ heat is retained in liquid in pipelines. The amount of LNG left in the two pipelines at the end of holding period is about 844,000 kg.

This paragraph describes the heat leak calculations for the pipeline without LNG left in it during holding mode. Since the pipelines do not contain LNG, we can assume that the pipe temperature is equal to ambient temperature. Before next LNG loading these pipelines must be precooled. If LNG is loaded without precooling of the pipelines, LNG will expand due to the heat and may create overpressure since its expansion ration is about 1:600. Following is a rough calculation of effect of holding-mode heat-leak on LNG loading, and it is presented as an example only without its use in the simulation. If it is assumed that pipelines are precooled to −125 °C using cold gases, the remaining cooling will be provided by LNG during starting of loading. For pipe metal thickness of 15 mm, metal specific heat capacity of 0.47 kJ/(kg K), and metal density of 7900 kg/m^3, and insulation thickness of about 13 cm, insulation specific heat capacity of 1.5 kJ/(kg K), and insulation density of 100 kg/m^3, the effective specific heat capacity (as explained in Section 2.1.3) of the pipe is 0.523 kJ/(kg K), and cooling required per unit length of pipe is 147 kJ/K. Thus total cooling required for two loading lines of 6000 m, is about 32 GJ, to cool pipes from −125 to −161 °C. Thus 32 GJ heat will be added to the LNG being loaded into ship-tanks, and will result in additional JBOG generation as compared to the case without holding-mode heat-leak. Further, for this option of holding-mode, pipeline cooling may take additional time (for example 20 to 60 min) at the beginning of the loading.

As discussed in this Section, holding-mode heat-leak varies depending on handling of loading line contents. To study effect of holding-mode heat-leak on JBOG profile, value of 40 GJ was used in the simulation for the case where holding-mode heat-leak is considered. At the beginning of LNG loading, 20 GJ heat was added in proportion to the mass flow rate, to each loading line for the first 422,000 kg LNG being loaded. The heat stream to add 20 GJ heat is depicted in Fig. 2 as Note-1.

2.1.2. *Pre-loading condition of ship tanks*

Due to heat leaks from environment during ballast voyage (voyage from LNG receiving terminal to LNG exporting terminal), temperature of the ship-tank rises above LNG temperature. LNG loading facilities usually set a limit for the temperature of the ship tank (for example, −125 °C), above this temperature the ship is not accepted for loading of LNG and it requires pre-cooling. In order to avoid rising of the temperature above this limit, a small amount of LNG is left in the ship tanks (called 'heel') after LNG unloading at LNG receiving terminals. The amount of LNG evaporated during ballast voyage depends on several factors including quantity of heel left after unloading LNG, length of voyage, ambient temperature, overall heat transfer coefficient of the tank, sea conditions, tank pressure, and BOG handling during ballast voyage. These conditions also determine the temperature of the ship tanks before loading of LNG. In this study, various pre-loading ship-tank temperatures viz. −125 °C, −135 °C, −145 °C, and −155 °C are considered. For easy comparison of these cases, same amount heel is assumed in each case. It is assumed that the amount of heel remaining in each ship tank at the end of ballast voyage (just before LNG loading) is 1 vol% of the ship tank. In order to identify the heel composition before LNG loading, following procedure was used. In Aspen Dynamics, a flash tank without any inlet stream and with only-vapor outlet stream was simulated (as that of LNG cargo during transportation). The initial hold-up of liquid LNG (heel) is taken as about 5 vol.% of the tank (the heel quantity does not affect the composition of liquid at any particular temperature; it only affects the amount of heat required to achieve that temperature). The initial LNG composition and temperatures are the same as those for the LNG loading stream. Enough amount of heat was added to increase the tank temperature to desired values (viz. −155, −145, −135, and −125 °C in sequence). During this time, the tank pressure was maintained to 1.06 bar by relieving excess vapors generated due to addition of the heat. The composition of liquid hold-up in the tank at respective temperatures was noted down. The heel compositions are given in Table 2. These heel compositions and corresponding ship-tank temperatures are used as initial conditions for LNG loading.

2.1.3. *Heat capacity calculation*

Ship-tank temperature is usually elevated than LNG temperature when LNG carriers reach at loading terminals. The degree of elevation depends on several factors such as length of ballast voyage (from LNG receiving terminal to loading terminal), amount of heel left during the ballast voyage, heat transfer coefficient of ship-tanks, ambient temperature, and sea conditions. The BOG generation due to factor 5 (explained in Paragraph 2 of Introduction) depends on mass of the tank and its heat capacity. To decrease any heat-leak the tank is insulated with rigid polyurethane foam on the outside of the 9% Nickel-Steel body. Based on assumed tank-volume, number of tanks, and their geometry, diameter of each spherical tank comes out to be 40.4 m (with equatorial cylindrical height 1 m and diameter 40.4 m). Thickness of metal layer is 5 cm and that of insulation is 22 cm. Density of the metal layer is 7900 kg/m^3, and that of rigid polyurethane is 100 kg/m^3. Using these dimensions and the densities, mass of the metal layer and insulation layer are calculated. Mass of the metal layer is calculated to be 2081 tons and that of insulation as 117 tons. Specific heat capacity of metal is taken as 0.47 kJ/(kg K), and that of insulation as 1.5 kJ/(kg K). Using Aspen Dynamic Simulation software, effect of heat capacity of ship-tank on process fluid can be calculated; however, it does not consider multiple layers of equipment. Ship-tank has multiple layers viz. metal layer and insulation layer. Therefore, overall mass and effective specific heat capacity are needed as input parameters for the simulation. The overall mass of the tank is calculated as addition of mass of each layer. In order to calculate effective specific heat capacity of the tank, Eqs. (1), (2), and (3) are used. One-degree change in LNG temperature causes almost one-degree change in inner metal layer. However, the corresponding temper-

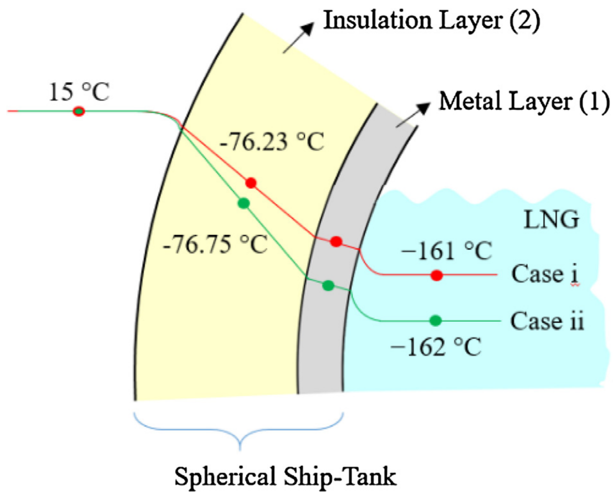

Fig. 3. Illustration of temperature profile for ship-tank at LNG temperature of (i) −161 °C and (ii) −162 °C.

ature change for the outer insulation layer is significantly less than one degree. Therefore, mere addition of heat capacities of two layers would not indicate the amount of heat to be removed from the ship-tank to cool it down by 1 °C. Parameter f1 and f2 are defined in Eqs. (1) and (2) respectively to indicate the change in average temperature of a layer with respect to the change in temperature of LNG inside the ship tank. Overall specific heat capacity for all-layers-together is termed here as 'effective specific heat capacity', which is calculated using Eq. (3).

$$\mathbf{f}_1 = \frac{\left(\mathbf{T_o} - \mathrm{T}_{av\mathbf{g}_{\mathbf{metal}}}\right)}{\left(\mathbf{T_o} - \mathbf{T_{LNG}}\right)} \tag{1}$$

$$\mathbf{f}_2 = \frac{\left(\mathbf{T_o} - \mathrm{T}_{av\mathbf{g}_{\mathbf{insul}}}\right)}{\left(\mathbf{T_o} - \mathbf{T_{LNG}}\right)} \tag{2}$$

where T_0 is the ambient temperature (15 °C); $T_{av\ metal}$ is the average temperature of the metal layer (−161.64 °C); $T_{avginsul}$ is average temperature of the insulation layer (-76.75 °C); and T_{LNG} is the reference LNG temperature (−162 °C). Value for f_1 is calculated to be 0.998, and for f_2 as 0.518.

$$\mathrm{C}_{\mathrm{p_{eff}}} = \frac{(\mathrm{C}_{\mathrm{p_1}}\boldsymbol{f}_1\boldsymbol{M}_1 + \mathrm{C}_{\mathrm{p_2}}\boldsymbol{f}_2\boldsymbol{M}_2)}{(\boldsymbol{M}_1 + \boldsymbol{M}_2)} \tag{3}$$

where $C_{p_{eff}}$ is the effective specific heat capacity the ship tank, C_{p_1} is the specific heat capacity of the metal layer; C_{p_2} is the specific heat capacity of the insulation layer; f_1 is the change in average temperature of the metal layer per degree change in temperature of LNG in the ship tank; f_2 is the change in average temperature of the insulation layer per degree change in temperature of LNG in the ship tank; M_1 is the mass of the metal layer; M_2 is the mass of the insulation layer for each ship tank.

Fig. 3 illustrates temperature profile of spherical wall of ship-tank for two different cases. Case i and case ii corresponds to LNG temperature of −161 °C and −162 °C respectively. When there is 1° change in LNG temperature, the corresponding change in average

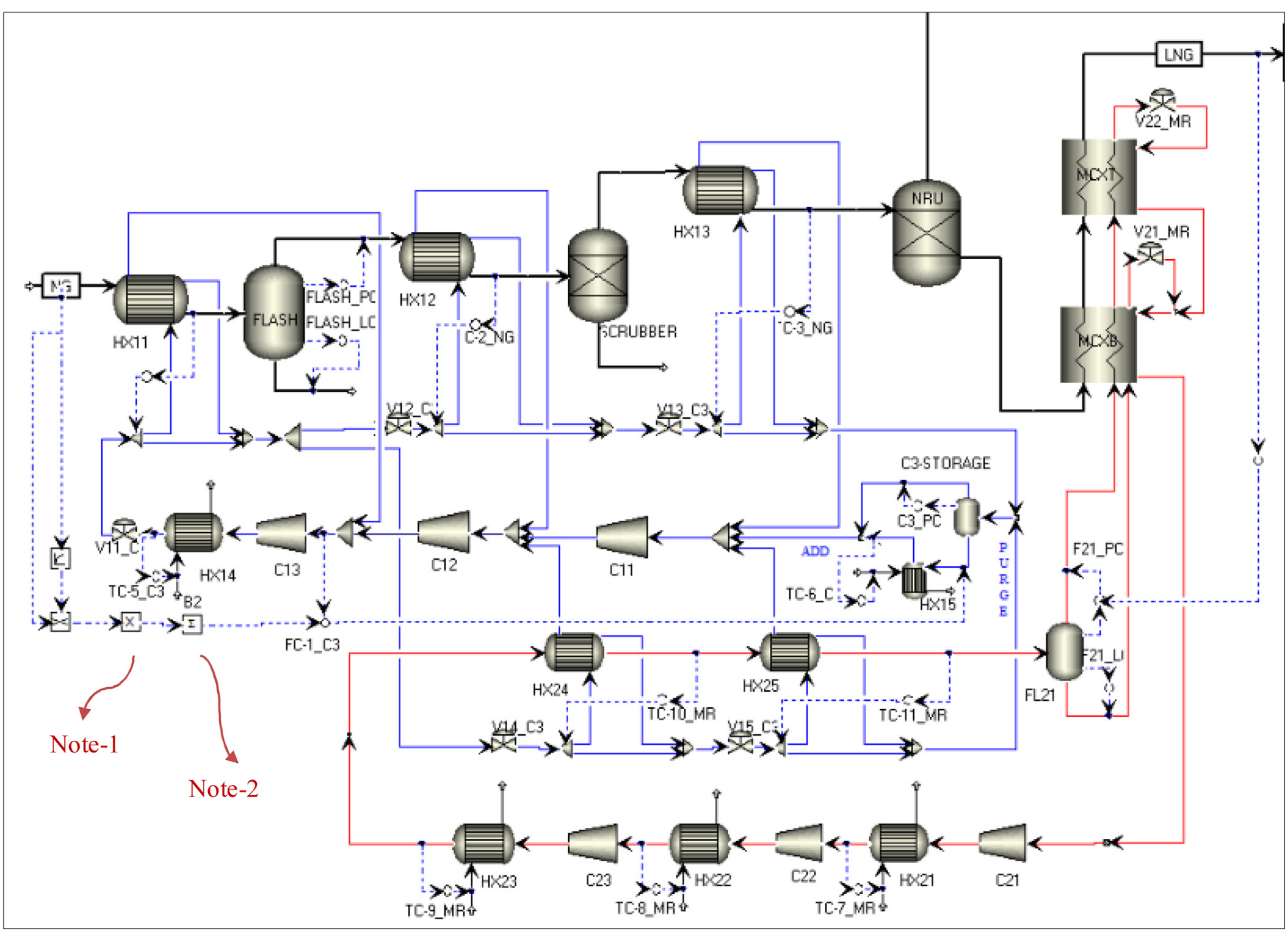

Fig. 4. Aspen dynamic process modeling schematic for LNG plant.

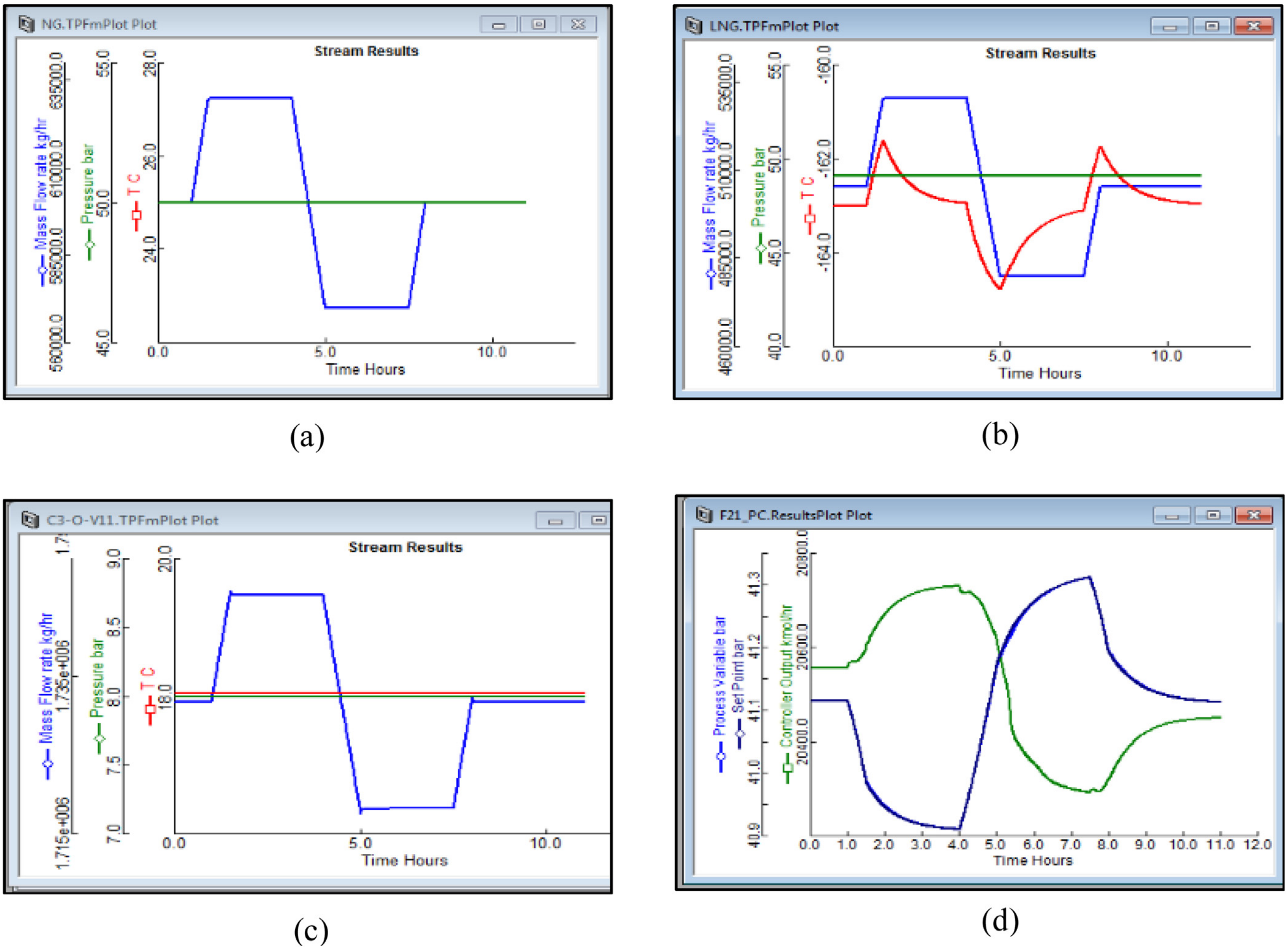

Fig. 5. Effect of (a) feed disturbance, on (b) LNG temperature, (c) propane flow rate, and (d) MR flash tank pressure.

temperature of insulation layer is about 0.52 °C. Parameter values of 0.486 kJ/(kg K) for $C_{p_{eff}}$ and 2,200,000 kg for total mass were used for each ship tank in Aspen simulation.

2.2. Modeling of control strategy for dynamic simulation

Fig. 4 shows process flow diagram modeled in dynamic simulation, with setup of PI controllers to control temperature of LNG at outlet of MCXT. Natural gas feed flow rate may change with time. Natural gas is pre-cooled to −34 °C using propane refrigerant. During disturbances in natural gas flow, the process temperature is controlled at set point by adjusting the amount of propane refrigerant. 'Note-1′ in Fig. 4 denotes the block which calculates required C3 amount to pre-cool natural gas. Temperature of the LNG stream (outlet of MCXT) is controlled by adjusting pressure of FL21 unit (the MR flash tank). Change in MR flash tank pressure changes the light and heavy stream composition and quantities, resulting in change in heat duty of MCHB and MCHT. Mixed refrigerant quantity is kept fixed. Therefore, propane required to precool MR is also fixed. 'Note-2' in Fig. 4 denotes the block which calculates total C3 requirement. The C3 flow is maintained at set point by adjusting liquid flow from C3 storage tank. Excess C3 is purged from refrigerant loop and sent to temporary C3 storage tank. Fig. 5 shows the sensitivity of some key process parameters in LNG plant towards disturbances in the feed flow rate. The key process parameters are – LNG temperature at outlet of MCXT, propane refrigerant flow rate, and MR flash tank pressure. Fig. 5-(a) shows step changes given to the feed flow rate. The natural gas flow rate was increased by 5% at 1 h of simulation run. The maximum variation in LNG temperature is less than 1 °C as shown in Fig. 5-(b), due to the manipulation in propane flow rate and MR flash tank pressure. The propane refrigerant flow increased by about 3% as shown in Fig. 5-(c), to maintain natural gas temperature constant at −34 °C at the outlet of HX13 unit. At the same time, FL21 tank pressure changed by about 0.2 bar as shown in Fig. 5-(d), to maintain LNG temperature constant at −162 °C

Controller setup for loading section is also shown in Fig. 2. In order to satisfy JBOG compressor capacity contraint and ship-tank cooling rate constraint, two controllers namely LNG_FC and Tank_TC are set up. When ship-tank level reaches 80 vol%, the loading rate is ramped down by the script (Task) written in the simulation. The Low_Selector block in Fig. 2 selects lowest of these values – output of LNG_FC, output of Tank_TC, and value chosen by the Task. This way each constraint is satisfied with just one manupulated variable – LNG loading rate. For a particular instance, whichever constraint has dominating effect on loading rate will require lowest loading rate. Adaptive control strategy was used for ship-tank pressure-controllers in the simulation, meaning values of proportional gain and integral action were adjusted during loading as per following requiremetns. When LNG flow rate is being ramped up or down, the controller shall be relatively faster to maintain tank pressure at the set point of 1.06 bar. When LNG flow is nearly constant, the controller shall be relatively slower to avoid oscillation in JBOG flow rate. Also, when JBOG flow reached near the com-

Table 3
List of Simulation Cases and Parameter Values.

Case ID	Holding mode heat leak considered? (Y/N)	Initial ship-tank temperature (°C)	JBOG Compressor capacity (kg/h)	Maximum allowed cooling-rate for ship-tank (°C per 20 min)
1A	**N**	−125	80,000	3
1B	**Y**	−125	80,000	3
2A	N	**−125**	80,000	3
2B	N	**−135**	80,000	3
2C	N	**−145**	80,000	3
2D	N	**−155**	80,000	3
3A	N	−125	**100,000**	3
3B	N	−125	**80,000**	3
3C	N	−125	**60,000**	3
4A	N	−125	80,000	**3**
4B	N	−125	80,000	**2**
4C	N	−125	80,000	**1.5**
4D	N	−125	80,000	**1**

Note: Case-1A, 2A, 3B, and 4A are one and the same. Listed repeatedly for the purpose of easy comparison.
The values in bold are changing within the respective category 1, 2, 3, and 4.

Table 4
The Simulation Results for LNG Loading Cases.

Case ID	Total JBOG (Million kg)	LNG Transferred (Million kg)	JBOG as percentage of LNG Transferred (%)	Time to reach Full Loading Rate (hr)	Loading Time (hr)	Holdup cooling time (hr)	Ship-tank Cooling Time (hr)
1A	1.58	69.22	2.28	11.03	25.30	9.05	13.95
1B	1.75	69.40	2.52	12.98	27.47	11.29	16.09
2A	1.58	69.22	2.28	11.03	25.30	9.05	13.95
2B	1.35	68.98	1.96	8.07	22.53	6.26	11.13
2C	1.13	68.73	1.64	4.87	19.89	3.67	8.31
2D	0.91	68.49	1.33	1.66	17.56	1.42	5.29
3A	1.56	69.21	2.25	7.77	22.74	6.66	11.70
3B	1.58	69.22	2.28	11.03	25.30	9.05	13.95
3C	1.64	69.29	2.37	18.50	30.41	13.59	18.51
4A	1.58	69.22	2.28	11.03	25.30	9.05	13.95
4B	1.58	69.22	2.28	11.21	25.51	9.27	14.16
4C	1.59	69.24	2.30	12.15	26.53	10.31	15.17
4D	1.63	69.29	2.35	14.90	29.53	13.39	18.11

pressor limits, the pressure-controllers were set to act relatively slower to avoid oscillations in the controller output. Note that the JBOG profiles may be affected by controller setup. If tank pressure is allowed to rise above set-point, less amount of vapors will be generated; conversely higher amount of vapors will be released if the tank pressure drops below the set-point. In the simulations performed, the pressure of the ship-tanks was maintained within ±0.03 bar of the set-point 1.06 bar.

2.3. Dynamic simulation of LNG ship loading

Maximum LNG loading rate is constrained by capacity of LNG loading lines. Here the maximum loading rate is considered to be 10,000 m^3/h at the conditions of liquid in the storage tanks i.e. 1.06 bar and −161.66 °C. The corresponding mass flow rate is about 4,882,360 kg/h. In Aspen Dynamics simulations performed in this study, LNG loading rate is controlled on the mass basis. The actual loading rate is constrained by two parameters – maximum allowable tank cooling rate and capacity of compressor on the ship or jetty. JBOG generation during LNG loading depends on several factors including – condition of loading facility before start of the loading, LNG loading rate, initial ship tank temperature, and heat leak during loading process. The following different cases are studied to obtain JBOG profile during LNG ship-loading. The cases are categorized based on the parameter to be changed. Category-1 includes two cases, to compare LNG loading with holding-mode heat-leak (HMHL) considerations, and without HMHL considerations. Case-1A is without HMHL considerations, and Case–1 B is with HMHL considerations. Category 2 considers effect of initial ship-tank temperature. Case-2A, Case-2B, Case-2C, and Case-2D represent initial ship-tank temperature of −125, −135, −145, and −155 °C respectively. Category 3 shows the effect of JBOG compressor capacity on LNG loading and JBOG generation. Case-3A, Case-3B, and Case-3C correspond to JBOG compressor capacity of 100,000 kg/hr, 80,000 kg/hr, and 60,000 kg/h respectively. Category 4 is the study of effect of maximum cooling-rate permitted for ship-tank. The restriction of the cooling-rate is to avoid thermal shocks to the tank materials. Case-4A considers the value of 3 °C cooling per 20 min (Huang et al., 2007). Case–4 B considers the value of 2 °C cooling per 20 min (North West Shelf Shipping Services Company, 2016). Additional values for the cooling rate are considered for the purpose of comparison. Case-4C considers value of 1.5, and Case-4D that of 1 °C cooling per 20 min. The values of parameters for each of these cases are listed in Table 3. Please note that Case-1A, Case-2A, Case-3B, and Case-4A are one and the same. It is repeated in each category, only for the ease of comparison and presentation. Thus, total ten different JBOG-profile cases are studied. The results are summarized in Table 4, and are discussed below categorically.

2.3.1. Effect of holding-mode heat-leak considerations on JBOG profile

Holding-mode heat-leak calculation is discussed in Section 2.1.1. Fig. 6 shows the dynamic JBOG profile along with corresponding LNG loading rate for Case-1A and Case-1B. In Case-1B, 40 GJ is the extra heat as compared to Case-1A. This heat results in more BOG generation. JBOG compressor capacity limit restricts

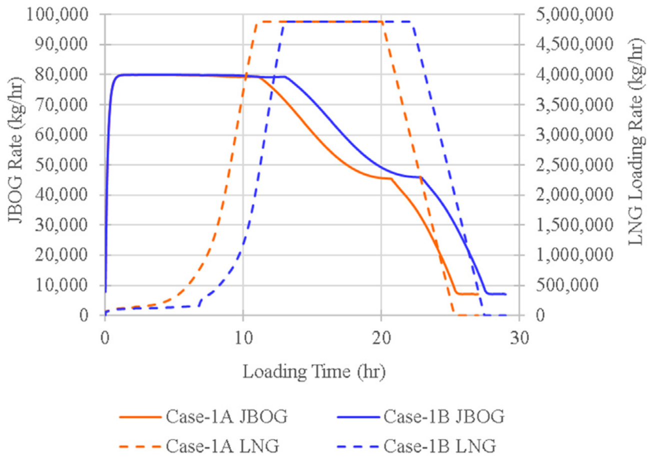

Fig. 6. JBOG profile and LNG loading rate for Case-1A and Case-1B.

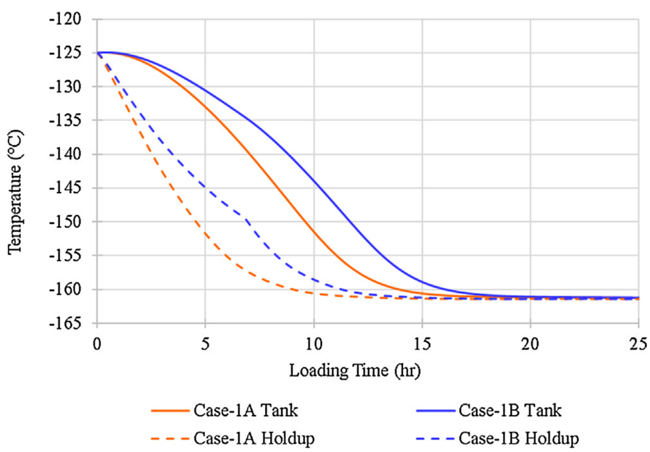

Fig. 7. Ship-tank temperature and holdup temperature for Case-1A and Case-1B.

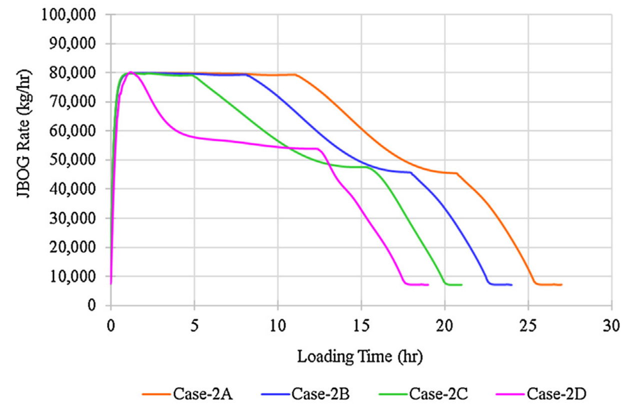

Fig. 8. JBOG profile for Case-2A through Case-2D.

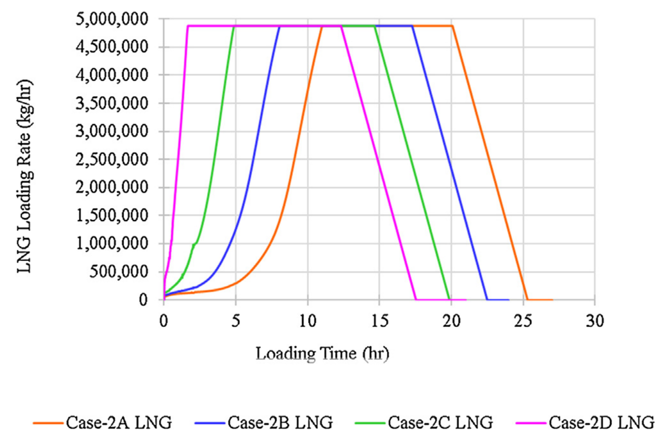

Fig. 9. LNG loading rate v/s loading time for Case-2A through Case-2D.

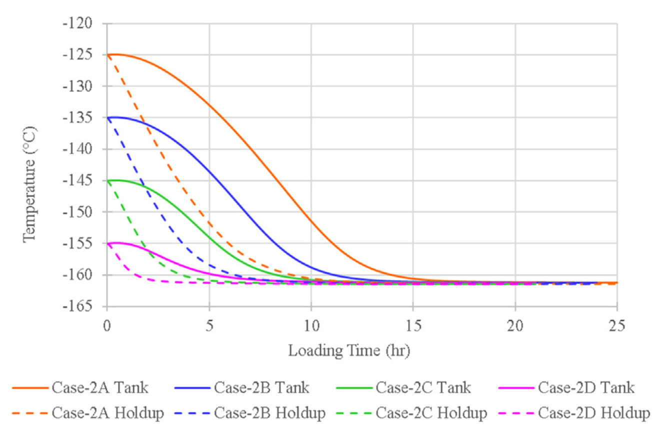

Fig. 10. Ship-tank temperature and holdup temperature for Case-2A though Case-2D.

LNG loading rate to keep JBOG within 80,000 kg/h set limit. Therefore, in Case-1B, LNG loading is initially slower compared to Case-A. For Case-1A, it takes about 11 h to achieve full LNG loading rate (2,441,180 kg/h per loading line), and Case–1 B takes about 13 h. In Case-1B, total JBOG generated is about 11% higher, tank cooling takes additional 2.2 h, as compared to Case-1A. During initial 5 to 7 h of loading, the loading rate is below 10% of the maximum; however, the JBOG generation is already at the compressor limit of 80,000 kg, because of the tanks being hotter than LNG temperature. Fig. 7 shows average ship-tank temperature (average metal temperature) and temperature of LNG in the ship-tank with respect to loading time. Heat from the hot ship-tank is absorbed by loaded LNG, and as a result, part of LNG evaporates into JBOG. Aspen considers vapor-liquid equilibrium in flash tanks, LNG (liquid) temperature, and JBOG coming out of the ship-tank will have same temperature at particular instance.

2.3.2. *Effect of initial ship-tank temperature on JBOG profile*

Initial ship-tank temperature affects JBOG generation until tank temperature reaches LNG temperature. Fig. 8 shows JBOG profile for Case-2A, Case-2B, Case-2C, and Case-2D. Quantity of total JBOG decreases by 14% for initial ship-tank temperature of −135 °C (Case-2B) as compared to that of −125 °C (case-2A). Similarly, the JBOG decrease is 16% for Case-2C, as compared Case-2B; and that is 20% for Case-2D as compared to Case-2C. Fig. 9 shows LNG loading rate with respect to loading time. Time required to achieve full LNG loading rate is about 11 h, 8.1 h, 4.9 h, and 1.7 h for Case-2A through Case-2D respectively. Fig. 10 shows temperature profile of ship-tank and LNG in the tank. The continuous lines represent ship-tank (metal) temperatures, and dotted lines represent holdup (LNG) temperatures. For any particular case, tank cooling takes about 3.8 to 5 h longer than cooling of tank-holdup to the temperature of loading LNG. Table 4 shows the results for total loading time, total JBOG generated, total LNG transferred to ship, and cooling time for each case. Usually cooling is faster in the beginning and slows down later when temperature gradient decreases. To calculate cooling time for tank metal and holdup, the temperature of −160 °C is considered as criteria. Total amount of LNG transferred

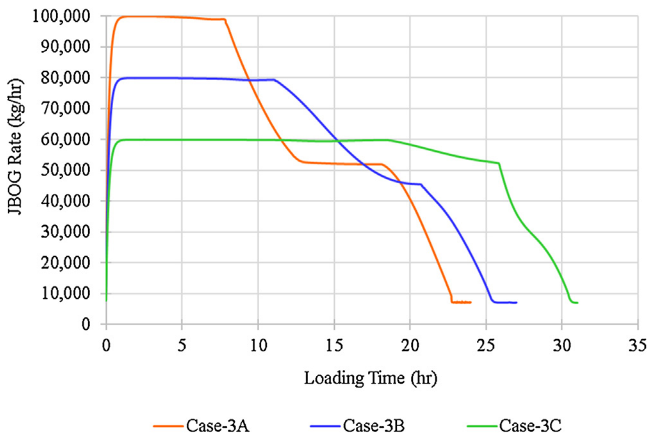

Fig. 11. JBOG profile for Case-3A through Case-3C.

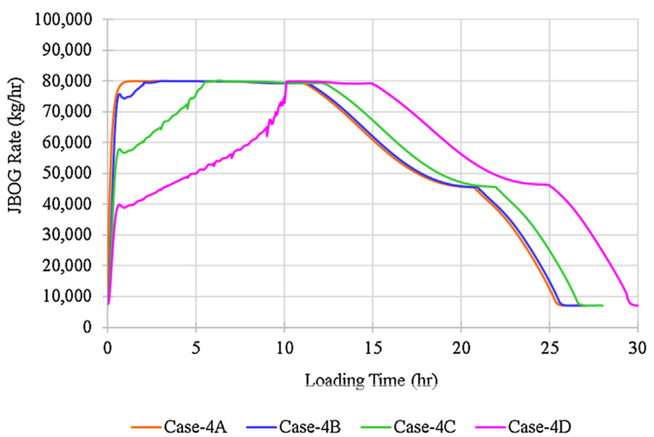

Fig. 12. JBOG profile for Case-4A through Case-4D.

to ship for loading in Case-2D is only 1.1% less as compared to Case-2A; however, the corresponding total-JBOG decrease is more than 42%.

2.3.3. Effect of JBOG-compressor capacity on JBOG profile

The JBOG-compressor capacity restricts LNG loading rate. The LNG loading profile decides loading time and also affects total-JBOG generation. For Case-3A, total-JBOG decrease is about 5.4% as compared to Case-3C, due to 7.7 h decrease in loading time. Higher capacity of compressors makes loading faster, and generate less JBOG as seen in Fig. 11. However, pipe size required to transfer JBOG will increase with the maximum JBOG flow rate. 24-inch pipeline is not sufficient to transfer JBOG at 100,000 kg/h rate, when compressed up to 2.5 bar pressure. Higher pressure of JBOG and larger pipe size may permit higher JBOG transfer rates.

2.3.4. Effect of ship-tank cooling-rate restriction on JBOG profile

Based on initial ship-tank temperature, tank cooling rate is higher during initial hours of loading. Once tank temperature reaches close to LNG temperature, obviously the cooling rate also decreases. Restriction on cooling rate limits LNG loading rate during initial period of loading. Fig. 12 shows JBOG profile for Case-4A though Case-4D. It can be seen that JBOG rate did not reach compressor capacity limits approximately within first 2 h for Case-4B, 5.5 h for Case-4C, and 10 h for Case-4D. Lower the value of maximum allowed cooling-rate, longer it takes to reach compressor limits, and also to complete the loading. Fig. 13 shows the corresponding tank holdup cooling rate for the period of loading. Lower the cooling rate limit, longer it takes for cooling. Tank cooling takes

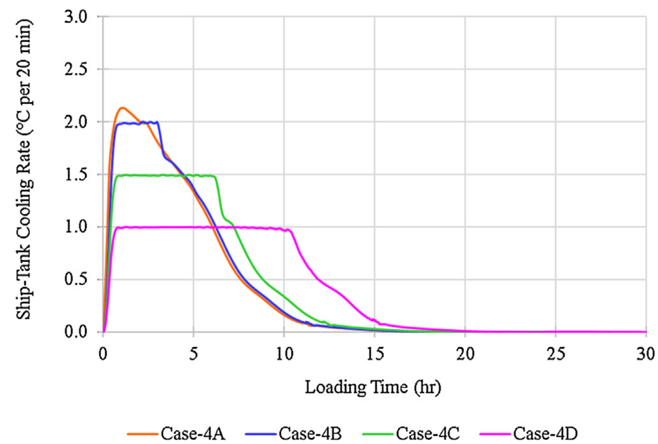

Fig. 13. Cooling-rate of ship-tank holdup for Case-4A through Case-4D.

about 3 h longer in Case-4D as compared to Case-4A. The difference in loading time of Case-4A and Case–4 B is only 15 min, because even in Case-4A (cooling limit of 3 °C per 20 min), the cooling rate reaches to value of only 2.1. It means, the compressor capacity constraint dominates the cooling rate constraint for Case-4A. For Case-4D cooling rate constraint dominates for the period up to first 10 h of loading.

Note that the holdup temperature-change is controlled in the simulations to represent cooling rate restriction. Because the tank temperature in the simulation is average temperature of the tank. The cooling rate restriction is for any portion of the tank, meaning even local temperature-change-rate must be within the specified limits. The average tank temperature does not reflect the maximum cooling occurring. The maximum cooling would be for the metal which is in contact with liquid LNG i.e. wetted wall would have maximum instantaneous cooling, since liquids have higher film heat transfer coefficients than vapors. At a particular moment, the maximum cooling taking place in any part of the tank would be equal to or less than the cooling of the process fluid (the holdup). For this reason, holdup temperature cooling rate is controlled in the simulations.

3. Fuel gas requirement for the LNG plant

In order to recover BOG, it would be necessary to find opportunities and ways to utilize the BOG. One of the strategies for BOG utilization is to use it as fuel gas. This section describes calculation of the amount of fuel gas required for LNG plant to run compressors in refrigeration cycles. This amount of BOG can be utilized in the form of fuel gas; and the excess BOG, if any, would require other strategy for its recovery. To run compressors using fuel is cheaper than using electricity. "Use of BOG as fuel gas" is a cheaper method to utilize BOG, as compared to other BOG recovery processes (Kurle et al., 2015). Fuel gas requirements for LNG plant is calculated with the consideration of two types of turbines – steam turbines and gas turbines. For base case, refrigerant compressor power requirement is about 850 GJ/h for LNG production of 500 tons/h. Since the process parameters are not optimized for minimum energy consumption, the actual energy requirement would be lower than the mentioned figures. Assuming thermal efficiency of steam turbines as 35% (Boyce, 2012), energy required from fuel gas will be about 2400 GJ/h. For calorific value of 0.05 GJ/kg of methane, about 48 ton/h methane is required. Considering average methane content of BOG as 85 mass%, BOG consumption for steam turbines comes out to be about 56.5 ton/h. Gas turbines are more efficient than steam turbines. For gas turbines with 60% thermal efficiency (Department of Energy, 2016), the BOG requirements will be about

33 ton/h for the same plant. Fuel gas can be taken from FBOG, TBOG, JBOG, or natural gas feed. FBOG flow shall be constant for a stable process. TBOG flow is also constant except during LNG ship loading. Due to high liquid flow rate out of storage tank during ship loading, make-up gas needs to be added to the storage tank to maintain the tank pressure and avoid potential tank implosion and safety hazard. JBOG is available only during ship loading, and its flowrate changes with loading time. Fluctuation in fuel gas flowrate is normally undesired. Also, during loading process, the availability of JBOG is more than fuel requirements of the plant. The fuel gas need can be fulfilled through one of the following ways: (1) use FBOG and TBOG as much available, and take the remaining from natural gas feed, (2) adjust the process parameters to obtain enough FBOG and TBOG to fulfill fuel gas requirements, (3) use FBOG, TBOG, and JBOG during ship loading, and FBOG, TBOG, and feed gas during holding mode. In any choice, JBOG handling needs to be addressed to avoid flaring and to utilize the energy. In previous work, several strategies to recover BOG are discussed (Kurle et al., 2015). In Section 4 and 5, additional options to recover JBOG are discussed.

4. Use of JBOG as make-up gas

During LNG ship loading, volume of LNG taken out of storage tanks is much higher than the volume of LNG feed and volume of TBOG generation. Therefore, it is necessary to add a makeup gas to the storage tank(s) in order to maintain tank pressure, and to avoid vacuum built up. The JBOG sent to the shore is still colder than ambient temperature. This JBOG can be used as make-up gas for the storage tanks during LNG ship loading. This make-up gas requirement is only during LNG ship loading, and JBOG is available to use during this time. JBOG generation is much higher than make-up gas requirements. So, part of JBOG can be used as make-up gas and the remaining needs to recovered using some other strategies such as BOG liquefaction, use-as-fuel-gas, or use-as-feed-gas. Other make-up gases (like nitrogen) on the facility might be at higher temperature as compared to JBOG, and can add additional heat to the tanks. Therefore, JBOG use as make-up gas can be a better option.

5. Storage and utilization of JBOG

As discussed earlier, JBOG rate varies with loading time, which makes it difficult to use for fuel gas. Also, for other BOG recovery strategies, change in JBOG rate will add significant disturbances thereby creating process control issues. If JBOG is to be used as feed gas, it may create significant disturbances in the liquefaction plant. If separate BOG liquefaction facility is to be built and used, the problem is that JBOG is not available continuously, since loading occurs only for about 18 to 25 h every 5 days, in this case. Even for higher capacity plants, LNG loading facility is on holding mode for about 2 to 3 days. It means, most of the time JBOG is not available to feed the BOG recovery facility. To address all these issues, JBOG can be stored and reused. The time-averaged-amount of JBOG can be withdrawn continuously from the JBOG storage. This will reduce size and cost of BOG recovery equipment. Also, steady supply of JBOG will be easy to control. Even in the case of process upsets, and emergencies, excessive BOG/vapors can be stored easily by compressing, and hence flaring can be avoided. Later, when the process recovers from upset, BOG can be utilized. However, this is at the cost of compression energy spent to compress JBOG to high pressure for storage purpose. The compression energy requirements are below 5% of energy that can be obtained from the recovered BOG. Process stability will be additional benefit from this strategy. Equipment required include compressor, air or water cooler, and high pressure storage tank.

Several LNG production sites have multiple trains with multiple berth areas, where simultaneous LNG loading of more than one LNG carrier takes place. In such case JBOG handling becomes more complex. One common storage can provide excellent buffer in managing JBOG, utilizing it at right place without potential process upsets.

The storage of BOG referred here is temporary storage, for the purpose of converting unsteady and intermittent process into stable and continuous process. In general, maximum residence time for BOG in storage will be one loading cycle time, for example, 138 h in this case. At 70 bar, 40 °C, BOG density is about 50 kg/m^3. Storage volume required for JBOG from one ship loading is about 40,000 m^3. At higher pressures, the volume required will be even less. Long pipeline or some other storage can act as temporary storage. Even if compressed-natural-gas storage tanks can be used to level the BOG feed to BOG recovery system or fuel gas. This would cost for capital investment; however, it comes with several benefits: (1) Stable process, no controllability and safety issues, (2) No flaring, no wastage of material and energy, (3) Environmental protection.

6. Concluding remarks

LNG loading is a dynamic process, and it was studied using dynamic simulation software. BOG generation during LNG loading varies with loading time due to ship tanks being relatively hotter initially, and change in loading rate. The factors affecting LNG loading are – LNG pipeline capacity, JBOG-compressor capacity, maximum allowed tank cooling-rate, JBOG pipeline capacity, initial ship-tank temperature, and condition of loading facility before the loading. For the studied case, JBOG generation rages from 1.2 to 2.5% of LNG transferred. LNG loading times range from 17 to 30 h depending on individual case. LNG loading time increased by about 8 h due to the ship-tank being hotter by 30 °C. Increasing compressor capacity from 80,000 kg to 100,000 kg, decreased the loading time by 2.5 h. If the maximum-allowed tank cooling-rate is below 2 °C per 20 min, it affects loading time significantly.

The fuel requirement for the studied case (4 MTPA LNG productions) was about 33,000 kg/h. The additional BOG generated needs to be reused/recovered using other strategies such as use-BOG-as-feed-gas, BOG liquefaction. Storing and reusing BOG was studied as one of the BOG recovery strategies. This strategy can nullify the controllability issues that can occur in other BOG recovery strategies due to intermittent and varying JBOG generation. It also makes BOG handling easier for simultaneous loading of multiple LNG vessels. In our future studies, detailed cost analysis of BOG (particularly jetty BOG) handling will be conducted to understand its applicability in LNG industry.

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