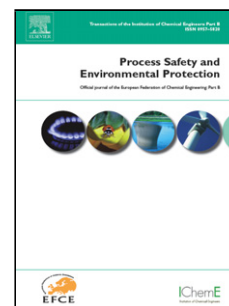


Accepted Manuscript

Title: Accident Risk-based Life Cycle Assessment
Methodology for Green and Safe fuel Selection
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PII: S0957-5820(17)30118-0
DOI: <http://dx.doi.org/doi:10.1016/j.psep.2017.04.005>
Reference: PSEP 1035

To appear in: *Process Safety and Environment Protection*

Received date: 6-5-2016
Revised date: 23-3-2017
Accepted date: 4-4-2017

Please cite this article as: S Khakzad, F Khan, R Abbassi, and N Khakzad. Accident risk-based life cycle assessment methodology for green and safe fuel selection, *Process Safety and Environmental Protection*, 109 pp. 268-287. ISSN 0957-5820.

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Accident Risk-based Life Cycle Assessment Methodology for Green and Safe fuel Selection

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Highlights

- A novel risk-based life cycle assessment methodology is proposed
- The novel methodology consider safety and environmental risk during the process life time
- Application of the methodology is demonstrated on LNG fuel life cycle

Abstract

Using the emissions produced during the entire life-cycle of a fuel or a product, Life-cycle assessment (LCA) is an effective technique widely used to estimate environmental impacts. However, most of the conventional LCA methods consider the impacts of voluntary releases such as discharged toxic substances and overlook involuntary risks such as risk of accidents associated with exploration, production, storage, process and transportation. Involuntary risk of

hazardous materials such as fuels could be quite significant and if ignored may result in inaccurate LCA. The present study aims to develop a methodology for accident risk-based life cycle assessment (ARBLCA) of fossil fuels by considering both the voluntary and involuntary risks. The application of the developed methodology is demonstrated for liquefied natural gas (LNG) and heavy fuel oil (HFO) as fuels of a hypothetical power plant. Adopting a Bayesian network approach, the comparative analysis of the fuels helps an analyst not only overcome data uncertainty but also to identify holistically greener and safer fuel options.

Keywords: Risk Analysis; Life Cycle Analysis; Risk-based LCA; Accident Analysis; Product Selection

1. Introduction

In recent decades, rapid industrial development has led to steady growth in global energy consumption. Meanwhile, the availability and well-controlled nature of fossil fuels have made them popular among energy consumers. Nevertheless, the combustion of fossil fuels results in greenhouse gas (GHG) emissions to the atmosphere, which consequently poses one of the greatest environmental threats in our time, that is, global warming. The average temperature of the Earth has risen between 0.4 and 0.8 °C over the past 100 years, and could increase by about 1.4 to 5.8 °C by the year 2100 [1]. This issue has raised questions about which fossil fuel is cleaner and has the least impact on the environment. Among fossil fuels, natural gas (NG) is believed to be a cleaner fuel since its combustion emits much lower GHGs than is emitted by oil and coal. Having the lowest carbon content of any fossil fuels, NG releases up to 50% less CO₂ than coal and much lesser CO₂, Nitrogen oxide (NO_x), Sulfur dioxide (SO₂), mercury (Hg), and particulate matters (PM) than oil and coal [2,3].

Less emission from combustion, however, does not tell the full story. NG primarily consists of methane (CH₄) which is a potent GHG and is more powerful than CO₂. Inevitable leakage of NG which can occur in different stages through its life-cycle results in significant GHG emissions [3]. Life-Cycle assessment (LCA) is a technique for systematic evaluation of the environmental impacts of a product or process throughout its entire life cycle, from raw material extraction to the final disposal or recycling.

Howarth et al. [4,5] studied the life-cycle emissions from shale gas production. Their study indicated that conventional gas has almost no advantage over coal whereas shale gas has higher life-cycle GHG emissions than do coal and oil, due largely to methane emissions during the extraction process. Hultman et al. [6] compared the life-cycle GHG footprints of conventional gas, shale gas and coal in the electricity generation sector. The authors showed that the GHG impacts of shale gas are slightly higher than those of conventional gas, while those of both conventional and shale gases remain considerably lower than those of coal, under standard assumptions. Similar attempts have been made to compare life cycle GHG emissions of conventional and unconventional NG, compressed natural gas (CNG), coal, and diesel [7,8].

However, these studies have not considered the issue of LCA from a broader perspective. In other words, it is merely the impacts of discharged toxic substances (voluntary risks) that have been taken into account while other important impacts such as those associated with risk of accidents such as fires and explosions (involuntary risks) occurring during the storage, production, process and transportation of fuels have been overlooked. This, in turn, can result in non-holistic and in some cases wrong decisions since an alternative with less environmental emissions (but more accidental risks) may seem less hazardous and thus preferable. Although there recently have been attempts to couple risk analysis and LCA to develop Life Cycle Risk Analysis (LCRA) methodologies [9-11], in none of them have the risks of abovementioned accidents have been taken into account. The present study aims to develop an Accident Risk-based Life Cycle Assessment (ARBLCA) methodology not only to consider the impacts of toxic environmental discharges which are assessed in conventional LCA but also to quantify the risks of potential fires and explosions resulting from the leakage of fuels. In this paper, the developed methodology is described in Section 2; the application of the methodology is demonstrated in Section 3, where a comparative ARBLCA of liquefied natural gas (LNG) and heavy fuel oil (HFO) as fuels of a power plant is performed. Sections 4 and 5 are devoted to the results and the conclusions, respectively.

2. Methodology

The method proposed in this study for ARBLCA integrates two widely known techniques in design and operation decision-making, LCA and Quantitative Risk Assessment (QRA), so as to make more accurate decisions by considering not only the emissions but also the accident risks.

The methodology includes four major phases: (i) forming a boundary for each life-cycle, (ii) performing LCA, (iii) hazard identification, and (iv) risk assessment. In order to compare the environmental impacts of different fuels, the outcomes of both LCA and QRA are converted to dollar value. Figure 1 illustrates a schematic diagram of ARBLCA methodology.

2.1. Life-Cycle Assessment

To holistically evaluate the environmental effects of a product or process, LCA should include raw materials extraction, manufacturing, processing, transportation, consumption, maintenance, recycling and waste disposal. Consequently, LCA can be used as an informed decision making tool to choose the alternative, whether products or processes, which is the least harmful to the environment. A typical LCA comprises several steps such as goal and scope determination, boundaries identification, inventory analysis, impact analysis, and improvement analysis [12].

LCA methods are basically data intensive and time consuming. Thus, it is necessary to set the analysis' goals and the boundaries in the first step in order to limit the analysis to important processes contributing the most to the LCA of a product. To this end, several LCA methodologies have been developed such as streamlined LCA [13] and input/output LCA [14, 15] which are less data intensive. Among the aforementioned steps, inventory analysis is of great importance as the quantities of both the required materials/energy and the environmental discharges (into air, water, and soil) are estimated. In the next step, the impact analysis, the effects of toxic discharges and emissions on the environment and on humans are assessed using exposure pathway modeling and dose-effect relationships. The aim of improvement analysis is to reduce the harmful effects by either reducing the amount of toxic discharges or devising appropriate safety measures [12]. It is worth noting that the application of risk analysis to LCA has been limited to the impact analysis or improvement analysis.

In life-cycle assessment with regard to GHG emission, data gathered from direct measurements of an emission source seem to provide the most reliable information. However, due to the lack of such data, emission factors, in spite of their limitations, have been widely employed for emissions estimation [16].

Emission factors are representative values relating the quantity of an emission (atmospheric

emission) to the activity generating the emission. To estimate these emission factors, the weight of emission is usually divided by the unit weight, volume, distance, or duration of the activity of concern (i.e., the emitting activity); for example, kilograms of CO₂ emitted per ton of coal burned. Such factors can be considered as the long-term average of available data yet with an acceptable level of quality obtained from all facilities in the emission source [16]. The general equation for emission estimation is:

$$E = A.EF.(1 - \frac{ER}{100}) \quad (1)$$

where E is the emission; A is the activity rate; EF is the emission factor, and ER is the overall emission reduction efficiency [16].

2.2. Quantitative Risk Assessment

In recent decades, accident risk assessment has become an integral part of decision making and design of process facilities dealing with large inventories of hazardous materials. Process plants are attributed with large inventories of hazardous materials along with many equipment items and complex pipeline networks. As a result, normal accidents which could easily be controlled or tolerated in other industrial facilities have the potential to turn into a catastrophe [17].

QRA focuses on quantifying the occurrence probability of envisaged accident scenarios. There are many techniques available, among which fault tree (FT), event tree (ET), and Bayesian network (BN) are very popular. Although conventional risk assessment methods have played an important role in identifying major risks and maintaining safety in process facilities, they have limitations which restrict their application to the risk analysis of complex and dependent systems. For example, conventional FT is not suitable for analyzing large systems, particularly if the system presents dependent failures [18-20].

2.2.1. Event Tree

ET is an inductive technique widely used in QRA. ET is used to investigate possible outcomes originating from an initiating event. The probabilities of the potential outcomes can be estimated using the probability of the initiating event and the operation/failure probabilities of a sequence of other events (e.g., safety barriers) taking place usually in a chronological order. In safety analysis, ET is used to quantify the probability of possible accident scenarios resulting from the occurrence of a hazardous event. Considering an undesired event as the initiating event (IE) in an ET, there will be two branches at every top event (TE) or safety measure. These branches usually represent the failure/function or presence/absence of safety barriers or occurrence/non-occurrence of TEs. Figure 3 illustrates a typical ET with an IE and two TEs. As a result, four outcomes or consequences could be expected, being C1, C2, C3, and C4.

Having the probabilities of the IE and TEs, the probabilities of the consequences can readily be calculated. For example, the probabilities of C1-C4 in Figure 2 can be calculated as:

$$P(C1) = P(IE) \cdot (1 - P(TE1)) \cdot (1 - P(TE2)) \quad (2)$$

$$P(C2) = P(IE) \cdot (1 - P(TE1)) \cdot P(TE2) \quad (3)$$

$$P(C3) = P(IE) \cdot P(TE1) \cdot (1 - P(TE2)) \quad (4)$$

$$P(C4) = P(IE) \cdot P(TE1) \cdot P(TE2) \quad (5)$$

In an ET usually the last consequence (e.g., C4 in Figure 2) has the lowest probability and the highest severity. ET has widely been used in accident modeling [21, 22], dynamic failure assessment [23], and dynamic risk assessment [24, 25].

2.2.2. Bayesian Network

BN is a graphical technique for reasoning under uncertainty. BN is a directed acyclic graph [26] in which the nodes represent random variables, arcs denote causal relationships between the linked nodes, and conditional probability tables (CPTs) assigned to the nodes identify the type and the strength of such causal relationships. In a BN, nodes with arcs directed from them are

called parents whereas nodes with arcs directed into them are called children. In this regard, the nodes with no parent are called root nodes while the nodes without any children are called leaf nodes. Other nodes are called intermediate nodes. In order to run the BN quantitatively, marginal probabilities must be assigned to the root nodes while conditional probabilities should be assigned to the leaf and intermediate nodes. Based on the conditional dependencies, BN represents the joint probability distribution of variables $P(U) = P(A_1, A_2, \dots, A_n)$ as:

$$P(U) = \prod_{i=1}^n P(A_i | pa(A_i)) \quad (6)$$

where $pa(A_i)$ is the parent set of A_i [27]. BN employs Bayes rule to update the prior probabilities of events given new information, called evidence E , to calculate the updated or so-called posterior probabilities. This new information usually becomes available during the operational life of a process [20]:

$$P(U) = \frac{P(U,E)}{P(E)} = \frac{P(U,E)}{\sum_u P(U,E)} \quad (7)$$

In addition to the capability of BN in probability updating, the flexible structure of BN enables one to model a wide variety of accident scenarios. Many attempts have been made over the past decades to use BN instead of conventional QRA techniques such as FT and ET [17, 18, 20, 21, 28-30].

3. Application of the methodology

3.1. Case study

To see the influence of the inclusion of accident risk analysis in LCA of different products/processes, we consider a hypothetical power plant in Holyrood in Newfoundland, Canada, which can operate using either LNG or HFO as the power plant fuel. After each fuel supply chain to the power plant is determined, LCA and QRA will be performed for specific stages along the supply chains. These specific stages should include the ones with most potential risk of accident and GHG emission. It should be noted that in order to simplify the last stage of the fossil fuel life cycles, that is, combustion in power plant, is excluded for the both fuels in the present study. Figures 3 and 4 illustrate the activities considered in ARBLCA of LNG and HFO, respectively.

3.2. Life-Cycle Assessment

Holyrood thermal station at the maximum is able to produce three billion kilowatt-hours of electricity per year [50]. This electricity amount is used as a basis for required calculations in the GHG emission LCA of LNG and HFO. For further calculations in LCA, heat rates (energy conversion efficiency) of 10,924 kJ/kWh and 10,903 kJ/kWh are assumed to be the power plant heat rates when it is fueled with LNG and HFO, respectively [31].

In the present study, only GHG emissions, among other emissions and environmental impacts during the life-cycle, are considered in the LCA phase. In this study, GHG emissions are reported on a common mass basis of carbon dioxide equivalents (CO₂e) using the global warming potential (GWP) of each gas from the Fifth Assessment Report (AR5) of Intergovernmental Panel on Climate Change (IPCC) in 2013 [32]. Table 1 shows the GWPs used for the GHGs inventories in the current study. All GHG results in this report are expressed as 100-year GWPs unless specified otherwise.

3.2.1. LCA of LNG

LNG is a colourless and odourless liquid, which is made by cooling NG to a temperature of about -160 °C at atmospheric pressure. The liquefaction process reduces NG volume to one six hundredth of its original volume, making it feasible to transport over long distances [33]. Using a NG heating value of 38.3 MJ/m³ [34] and a density of 0.67 kg/m³ [34], the total amount of NG required to generate 3 billion kilowatt hours of electricity can be estimated as 576,098,597 kg using the equation below [35]:

$$\text{Amount of fuel used per kWh} = \frac{\text{power plant heat rate (Joule per kWh)}}{\text{fuel heat content (Joule per cubic meter)}} \quad (8)$$

An LNG plant is supposed to be developed in Goldboro in Nova Scotia, Canada, by 2018 [51]; thus, we assume that LNG fuel required for the power plant in Holyrood, Newfoundland, can be provided from Goldboro. After being extracted and processed at Thebaud platform, located offshore Nova Scotia, the NG is transported through a pipeline to the Goldboro plant. NG is then converted into LNG and stored in the Goldboro plant for exportation. LNG is then transported to

Holyrood by ship, stored, and then re-gasified in a re-gasification terminal. Finally, the gas is sent to the hypothetical power plant in Holyrood via pipeline.

It is assumed that the regasification plant is near the power plant, so that emissions associated with NG transportation to the power plant are negligible. Furthermore, as LNG storage has insignificant emissions when compared to the other stages, it will not be considered in the LCA in the present work. The sequence of the foregoing processes considered in the LCA of LNG is depicted in the left-hand side block of Figure 3. It is worth mentioning that the results and assumptions of the National Energy Technology Laboratory (NETL) inventory [7] for conventional offshore gas are those which have mostly been used for the LCA of LNG in the present study.

3.2.1.1. Natural gas extraction

Extraction of NG is the first section in the LCA of LNG and depending on the well type. This section can include sub-sections such as well construction and installation, well completion, liquid unloading, and workovers. These activities all result in GHG emissions either by energy combustion or by gas release occurring during the operations. Another key source of GHG emission, which contributes to almost all sections of LCA, is fugitive emissions from the operational equipment. The emission sources accounted for NG extraction in this study include well completion, gas venting from wet seal degassing, and fugitives from the equipment.

The emission related to well completion is the NG release that occurs during a well development, before equipment have been installed for NG recovery. Well completion causes a significant amount of GHG emission although it is not a part of daily operations. The methane emission from the completion of a conventional well is based on emission factor developed by EPA: 36.65 Mcf of methane per completion [7]. The emission factor for wet seal degassing accounts for the NG lost during the regeneration of wet seal oil, which is used for centrifugal compressors. In this study, we use the emission factor calculated by NETL, which is based on sampled venting emissions from 15 offshore platforms by EPA, and production rate of a year in the US. This emission factor is 0.0069 m³ of vented gas per cubic meter of produced NG [7]. The fugitive emissions considered in this study include two sorts of emissions; the emissions that can be and those that can not be captured for flaring. The latter is related to the methane leakage of

pneumatic valves and other process control systems. The emission factor for these devices, which is estimated to be similar to that of wet seal degassing, is 1.95×10^{-6} kg of methane per kg of produced NG [7]. Likewise, gas released from mishaps and equipment such as separators and pumps cannot be captured for flaring. NG is also released from wellhead and equipment like heaters and blowdown vessel, which can be captured for flaring. For conventional wells, 51% of these emissions are flared, while the balance is vented to the atmosphere [7]. Table 2 shows the emission factors for fugitive emissions from extraction section. The emission factors for unprocessed NG flaring based on API [34] are shown in Table 3.

3.2.1.2. Natural gas processing

To meet pipeline quality, raw NG must be cleaned from contaminants such as water, carbon dioxide, and hydrogen sulfide (H_2S). This is a pre-treatment of raw NG at extraction site since a complete process is usually done at a processing or liquefaction plant. This process takes place through different operations depending on the NG type. In this study, we consider key processing operations including acid gas removal (AGR) and dehydration.

Amine-based processes are technologies widely used in AGR. The energy combustion by an amine reboiler is the major source of GHG emissions in AGR process. In order to estimate GHG emissions by amine reboiler, EPA emission factors for industrial boilers [16], which are fuelled by NG, are applied in this study. In addition to the emissions resulting from the energy combustion, a portion of CH_4 absorbed by amine solution and naturally-occurring CO_2 in raw NG are vented to the atmosphere [7]. Table 4 shows the emission factors for AGR process.

Glycol dehydration is the most common method of water removal from raw NG. Similar to AGR process, GHG emissions from dehydration operations include fuel combustion and venting emissions. Reboiler, which here is assumed to be heated by NG combustion, is the only equipment in the dehydration system that consumes fuel. In addition to absorbing water, the glycol solution also absorbs methane from the NG stream. Flash separators capture most of this

methane during the process; nonetheless, small amounts of it are vented from dehydrators [7]. Table 5 shows the emission factors for dehydration operation.

3.2.1.3. Natural gas transportation (pipeline)

This study assumes that NG, after extraction and process in offshore oil field, is transported to Goldboro LNG plant by pipeline. Most emissions related to NG transportation are produced due to energy combustion by compressors used to increase NG pressure. The energy required for compressor operations is based on a comparison between power requirements and compression ratios. This analysis assumes that the inlet pressure to compressors at the NG extraction and processing site is 345 kPa while the outlet pressure is 5516 kPa, a standard pressure for pipeline transportation of NG.

Gas powered centrifugal compressors are commonly used at offshore NG extraction sites. A two-stage centrifugal compressor with an inlet pressure of 345 kPa and an outlet pressure of 5516 kPa has a power requirement of 5 watts per m^3 of NG [36]. The GHG emission for the operation of a wellhead centrifugal compressor is shown in Table 6.

The pipeline distance in the present study was estimated as 225 km, which is the approximate distance between the extraction field and the location of the hypothetical LNG plant. To keep the desired NG pressure, compressor stations are necessary every 80 to 160 kilometers along the pipelines. Therefore, it is assumed that there are two compressor stations along the pipeline; the amount of GHG emissions associated with each station is 30% of the total emission produced by the wellhead compressor.

3.2.1.4. Natural gas liquefaction

NG that arrives at a LNG plant, prior to liquefaction, is further treated in order to remove any residual water, sulfur-containing species, and CO_2 that might still be presented after the pre-processing. Moreover, other components that could freeze under the low temperatures (e.g. benzene) during liquefaction are removed as well as those which could be harmful to the liquefaction facility (e.g. mercury). The liquefaction process entails chilling the cleaned NG using refrigerants. Going through stages of pre-cooling, liquefaction and sub-cooling, the NG reaches the desired temperature and is then stored as LNG in double-walled tanks at atmospheric

pressure. GHG emissions associated with the liquefaction process are mainly due to the fuel gas combustion needed for power refrigeration compressors and electrical generators, fired heaters, flares, incinerators, venting of CO₂, and fugitive emissions in the process [37].

A few studies have been conducted to quantify the amount of GHG emissions from LNG plants. From those, an estimation of 64 kg CO₂ e/MWh by NETL [52] was selected for the liquefaction GHG emissions in the present analysis.

3.2.1.5. LNG transportation

LNG is transported by specially designed marine tankers delivering their load to receiving terminals. The main source of GHG emissions in LNG tankers (ships) is the fuel combustion needed to power their propulsion systems. Hence, emissions from LNG transportation relates to the volume of LNG transported and the distance travelled by ships. It is assumed that boil-off gases (BOG) from the vessels are either consumed as fuel in engines or liquefied and returned to the ship tanks.

Jaramillo et al. [38] conducted a comparative study of LNG, coal, and gas life-cycle carbon emissions, and used Equation (9) for estimation of LNG carriers. Their formula was adapted in this study to estimate LNG tankers GHG emissions. Furthermore, the distance travelled by the LNG tankers was estimated, using Google Maps, as 1000 km.

$$Emission\ factor = \frac{(EF) \sum \left[\left(2 * roundup \left(\frac{LNGx}{TC} \right) \right) * \frac{Dx}{TS} * FC * \frac{1}{24} \right]}{LNGt} \quad (9)$$

where EF is the tanker emission factor of 3,200 kg CO₂/ton of fuel consumed; 2 is the number of trips each tanker does for delivery of each load; LNGx is the amount of NG (in cubic meters) brought from each country; TC is the tanker capacity in cubic meters of natural gas (assumed to be 120,000 m³ of LNG); Dx is the distance from each country; TS is the tanker speed of 14 knots; FC is a fuel consumption of 41 tons of fuel per day; 24 is the number of hours in a day; and LNGt is the total volume of LNG [39].

3.2.1.6. LNG regasification

Regasification plants, generally incorporated into LNG receiving terminals, return the LNG back to its gaseous state. In regasification plants, LNG is initially pumped from the ships into the terminal LNG storage tanks. Then, LNG is either loaded onto trucks for transport to smaller consumers' locations, or pumped to higher pressure through high pressure pumps, vaporized to higher pressure and entered into the transmission and distribution pipeline systems. In a regasification LNG terminal, GHG emission sources include: methane leakage from equipment such as flanges, valves, compressors and pumps, venting emissions from LNG pumps during maintenance, flaring of BOG from storage tanks during ship unloading (if BOG rate exceeds BOG compressor capacity), emissions from fuel combustion used for the vaporization process, and venting from the vaporization process and from BOG compressors during maintenance [37]. The estimation of 20 kg CO₂ e/MWh by NETL [52] was selected for the GHG emissions related to the regasification plant in this study.

3.2.2. LCA of HFO

HFO is a high-viscosity residual oil that remains after the distillate fuel oils and lighter hydrocarbons are distilled off in refinery operations. HFO is a refinery's cheapest product, used for the production of electric power, space heating, vessel bunkering, and various industrial purposes [40].

Using a HFO heat content of 6633 kJ/barrel [41], the total amount of HFO required to generate 3 billion kilowatt hours of electricity in the Holyrood power plant is estimated to be 4,929,000 barrels using Equation (8). According to American Petroleum Institute (API), based on the average of yields for US refineries in 2005, 1.7 gallons of HFO are obtained from one barrel (42 gallons) of crude oil. Therefore, approximately 121,775,300 barrels of crude oil are needed to produce 4,929,000 barrels of HFO.

The required oil fuel for the Holyrood thermal plant is supplied by Philips 66 Company, which is an American company with no refinery in Canada. Thus, in this study, the origin of oil fuel has been considered in the Gulf of Mexico, the U.S.A. It is supposed that the crude oil extracted from the Mars platform in the Gulf is transported by ships to one of Philips 66's refineries, the Alliance Refinery in Louisiana, U.S.A. After processing the crude oil, the produced oil fuel is

stored, and then shipped to Holyrood thermal plant by ship tankers. The sequence of the aforementioned processes is depicted in the left-hand side block in Figure 4.

3.2.2.1. Crude oil recovery

Crude oil recovery is the first section of HFO life-cycle assessment, and includes well drilling, crude oil extraction, and crude oil processing. Rahman et al. [42] quantified the GHG emissions from the recovery of five North American conventional crude oils. One crude oil included in their analysis was Mars crude oil, extracted from the Mars platform which is used in this study as the crude oil extraction site. Rahman et al. [42] estimated air emissions associated with crude oil recovery operations such as well drilling, crude oil extraction, crude oil processing, and also emissions from venting, flaring, fugitives, and land-use change. Among these emissions, crude oil extraction, crude oil processing, and emissions from venting, flaring and fugitives were taken into account in the present study.

Crude oil extraction consists of a number of steps in order to raise the crude oil from the reservoir to the surface. Extraction of crude oil consumes a large amount of energy that consequently results in large GHG emissions. It is worthwhile mentioning that this energy is mainly used by recovery techniques – primary, secondary, and enhanced methods – applied to increase the production of the oil reservoir. In the primary method where extraction is at the early stages, the reservoir pressure is enough to flow the oil through the production well; although, artificial lift technologies such as pumps are used when the pressure drops within the reservoir. Aging the reservoir and consequent decrease of the pressure make it necessary to use the secondary method, such that water/gas is injected into the reservoir to boost the reservoir pressure for production. Further, the enhanced recovery method including thermal recovery (steam injection), gas injection (i.e., natural gas, nitrogen, carbon dioxide), and chemical injection (i.e., polymers and detergent) is used to mobilize the remaining oil. Rahman et al. [42] calculated GHG emissions of crude oil extraction based on basic energy combustion equations for pumps, compressors, and other electric equipment. The emission from the Mars crude oil was estimated to be 1.26 g-CO₂ equivalent per each MJ of crude extracted [42].

Being mixed with water and gas after extraction, the crude oil needs processing to meet transportation quality requirements. The energy consumption needed to remove and treat these phases contributes to GHG emission. A gravity separator is usually used to separate oil, gas, and water, which is not a significant source of GHG emission. Natural gas-fired reboilers providing the heat required for crude oil stabilization, and pumps are considered as main causes of emissions for stabilizing crude oil. Treatment of associated gas using an amine treater and a glycol dehydrator is the next step in crude oil processing. This has already been explained in NG processing (see Section 3.2.1.2). The water that comes out of the reservoir along with the crude oil, must meet environmental regulations before discharge. Therefore, the last step of crude oil processing entails treatment of the water associated with crude oil. This treatment, which is energy consuming and a source of GHG emission, includes reduction of oil, grease, sodium, and TDS (total dissolved solids) in water. The emission factor for Mars crude oil processing estimated by Rahman et al. [42] is 0.79 g-CO₂ e/MJ.

Venting – release of associated NG – and flaring – combustion of associated NG – are inevitable sources of GHG emissions in extraction sites. Venting and flaring may occur during emergency operations and are necessary where a stream of NG cannot be safely or economically recovered. The flaring combustion product of NG includes carbon dioxide, methane, and nitrous oxide. The mass composition of unprocessed NG, used in this study to model NG flaring, is 78.3% CH₄, 1.51% CO₂, 1.77% nitrogen, and 17.8% non-methane hydrocarbons [43]. The emission factors for unprocessed NG flaring are shown in Table 3.

The leakage of NG through equipment such as valves, pumps, compressors, and other devices during extraction and processing operations is called fugitive emissions. These emissions usually cannot be captured for flaring due to economic limitations [7,42]. Rahman et al. [42] estimated venting, flaring, and fugitive volumes to be 1.33, 0.78, and 0.21 m³ of NG per m³ of crude oil extracted, respectively.

3.2.2.2. Crude oil transportation

Transportation of crude oil by ocean is generally done through subsea pipelines or ocean tankers. In this study, marine tankers are considered to transport both the crude oil from the producing field to the refinery and the HFO from the refinery to the power plant. Ocean going vessels are

among the major sources of GHG emissions in the world. This is primarily due to the large quantity of fuel, mostly residual fuel oil, consumed by engines to propel the vessels. GHG emission associated with maritime vessels is highly debated, and many studies have been conducted to evaluate their impacts. In this study, the approach of Clarkson [44] is adopted. That is, ocean oil tankers with slow-speed diesel main engine, medium-speed diesel auxiliary engine, and a capacity of 700,000 barrels are considered for both crude oil and HFO transportation. There is a difference between crude oil and HFO densities, which in turn affects the volume of the liquids transported by each marine tanker trip. Because this difference is insignificant, we assume that the amounts of crude oil and HFO transported in each trip are the same. The ocean tankers specifications are listed in Table 7.

The emissions produced by main and auxiliary engines are calculated separately. The load factor for the main engine in each mode is calculated based upon the propeller law relationship equation [45]. Since the vessels do not operate at 100% maximum continuous rating (MCR), the correction of 0.83 is added for compensation [46].

$$LF = 0.83 \times \left(\frac{AS}{SS}\right)^3 \quad (10)$$

where LF is load factor; AS is actual speed of the vessel, and SS is the service speed of the vessel. In order to calculate the vessel emissions, individual emission factors are required for each pollutant being investigated. Emission factors suggested by Goldsworthy & Renilson [47] were used in this study. These emission factors are presented in Table 8.

The amount of emissions produced by both the main and auxiliary engines is then calculated using Equation 6, proposed by Corbett et al [48].

$$E = \frac{P \times LF \times A \times EF}{1000} \quad (11)$$

where E is the amount of emission in kg; P is the installed power of engine; A is the time of operation in that mode, and EF is the emission factor in g/kWh. The distances were estimated as 200 kms from the oil field to the refinery, and 4,500 kms from the refinery to the power plant using Google Map.

3.2.2.3. Crude oil refining

After crude oil arrives at the refinery, it is refined (i.e. separated into smaller fractions) to produce various petroleum products. Refineries are considered one of the largest GHG-emission sources in industrial activities around the world, mainly because of their vast amount of energy consumption. Rahman et al. [49] developed a refinery model in HYSYS to quantify the energy consumption in each process unit of the refinery. The amount of energy consumed and the volume of the final products produced in the refinery were used as inputs to a spreadsheet-based model, FUNNELGHG-CCO, which traces energy combustion and quantifies GHG emissions associated with each final product.

They ran the model for different crude oils to process 150,000 barrels per day. Considering that electricity, heat, and steam are required for the refinery processing unit, it was assumed that NG is used to produce the heat and steam. To calculate the amount of NG required for heating and steam production, the heater and boiler efficiencies were taken as 80% and 75%, respectively. The total GHG emissions were determined from the amount of NG, required electricity, and emission factors for the combustion of NG and grid electricity. The model estimated the emission associated with the Mars crude oil refining to be 7.97×10^9 gr-CO₂ equivalents per day.

3.3. Accident Risk Assessment

In order for a holistic risk assessment, the risks of potential fires and explosions for likely releases of LNG and HFO should be calculated at different stages from extraction at offshore drilling rigs to consumption at the power plant. For this purpose, we employ BN technique to analyze the root causes of unwanted releases of flammable materials LNG and HFO while ET technique is used to explore the consequences of such releases.

3.3.1. LNG life-cycle risk assessment

The sequence of the processes which will be considered in the risk assessment of LNG life-cycle is depicted in the right-hand side block of Figure 3.

3.3.1.1. Natural gas extraction

As can be seen from Figure 3, the first process considered in risk analysis of LNG life-cycle in this study is the extraction of NG at the offshore drilling rig. Assuming an overbalanced drilling, an undesired kick and the ensuing blowout are considered as the most likely release scenario [17,25]. The developed BN of an undesired kick and the ET of the evolution of the kick to a blowout have been displayed in Figures 5 and 6, respectively.

3.3.1.2. Natural gas transportation (pipeline)

After being extracted at the Thebaud platform, NG is transported ashore via subsea pipeline. The pipe rupture can then be considered as the most likely release scenario as shown in the BN of Figure A-1 (see Appendix A). Based on the function/malfunction of the safety measures in place, the consequences of a pipe rupture can be investigated using the ET as shown in Figure A-2.

3.3.1.3. Natural gas liquefaction

The natural gas which is transported ashore should be liquefied for ease of storage and transportation. The root causes of a gas release scenario have been displayed in the BN of Figure A-3, and the corresponding ET to investigate the likely consequences of such gas releases have been depicted in Figure A-4.

3.3.1.4. LNG storage

After being liquefied, LNG is stored in LNG storage tanks. These storage tanks can store LNG at the very low temperature of $-162\text{ }^{\circ}\text{C}$ usually due to their double-container structure. The inner container contains LNG while the outer one contains insulation materials. In LNG storage tanks if LNG vapor is not released, the pressure and temperature within the tank will increase which can thus lead to a tank explosion. LNG is a cryogen, and is kept in its liquid state at very low temperatures. The temperature within the tank will remain constant if the pressure is kept

constant by allowing the boil off gas to escape from the tank. This is known as auto-refrigeration. The BN in Figure A-5 illustrates the root causes which can result in a gas release. The consequences of such a release are shown using the ET in Figure A-6.

3.3.1.5. LNG transportation (shipping)

The LNG stored at Goldboro Plant, Nova Scotia, is shipped by marine tankers to Holyrood, Newfoundland. The major accident scenarios which could result in an LNG release consist of either damage to the tanks or accidents which threaten the ship's physical/operational integrity. BN developed in Figures A-7 displays the root causes of such accident scenarios. Likewise, the likely outcomes of such an LNG release can be represented as the ET in Figure A-6.

3.3.1.6. LNG re-gasification

In order to be used as a fuel, LNG should be returned to its gaseous state via re-gasification process. In a conventional re-gasification plant, LNG is heated by sea water to convert it to NG/methane gas. The root causes of an undesired gas release during the re-gasification process have been depicted in Figure A-8. The ET of Figure A-4 can also be used to analyze potential accidents.

3.3.2. HFO life-cycle risk assessment

The sequence of the processes which will be considered in risk analysis of HFO life-cycle is depicted in the right-hand side block of Figure 4.

3.3.2.1. Crude oil extraction

In the present study, the extraction of both NG and crude oil is conducted using offshore drilling platforms. As such, assuming an overbalanced drilling operation, the root causes of a kick as the most likely release scenario and the potential blowout can be modeled using the same BN and ET as developed in Figures 5 and 6, respectively.

3.3.2.2. Crude oil transportation (shipping)

After being extracted from the Gulf of Mexico, crude oil is transported to the Alliance refinery via marine tankers. Similar to that of LNG, the root causes of a hydrocarbon release can be

depicted in BN of Figure A-9. The likely outcomes of such accident are shown in ET of Figure A-10.

3.3.2.3. Crude oil storage

After arriving at the refinery, the crude is stored in storage tanks before being refined into products of interest. Storage tanks come in different sizes and shapes with special applications requiring tanks to be rectangular, vertical or horizontal cylinders, or even spherical. Horizontal cylinders and spheres are generally used for pressurized storage of hydrocarbon or chemical products. For crude oil and its products, however, the atmospheric or low-pressure storage tanks are usually used being vertical cylindrical in shape with fixed or floating roofs. The BN for an unwanted release of fuel oil from the storage tanks is illustrated in Figure A-11. The ET of Figure A-10 can be used to investigate the potential consequences of such an accident.

3.3.2.4. Crude oil refining

In the Alliance Refinery, the crude oil is then processed and refined in order to be converted into more useful products such as petroleum naphtha, gasoline, diesel, asphalt base, heating oil, kerosene and liquefied petroleum gas (LPG). Generally, crude oil is heated and changed into a gas using a fired boiler (furnace). The hot gases are passed into the bottom of a distillation column and become cooler as they move up the column. As the gases cool below their boiling point, they condense into a liquid. The liquids are then drawn off the distillation column at specific heights, ranging from heavy residuals at the bottom, raw diesel fuels in the mid-sections, and raw gasoline at the top. These raw fractions are then processed further to make several different finished products.

Considering a distillation column, a furnace, and a heat exchanger as the major hazard installations in the refinery, a BN for unwanted release of flammable materials from these have been developed as depicted in Figure A-12. The likely consequences which such a release can pose are presented in the ET of Figure A-13.

3.3.2.5. HFO transportation (shipping)

The HFO produced in the Alliance refinery is then transported to the Hollyrood thermal station. Since marine tankers are considered to transport both HFO and crude oil in the present study, the

root causes of a hydrocarbon release and likely consequences can be presented using the same BN and ET as developed in Figures A-9 and A-10, respectively.

4. Results and Discussion

4.1. Comparison of life-cycle emissions

Based on the total volume of the fossil fuels required by the Hollyrood power plant to generate annual electricity, the emission factors and the life-cycle GHG emissions were estimated for both LNG and HFO.

These emissions in the form of CO₂ equivalent (tons CO₂ e) are presented in Tables 9 and 10 for LNG and HFO, respectively. However, it should be noted that due to the generic data and the emission factors mainly extracted from the literatures and also the simplified assumptions made in the calculations of life cycle emissions, there is a high level of uncertainty in the results of the present study. The results of the LCA indicate that the total GHG emissions produced throughout HFO life-cycle (8,460,180 tons CO₂ e) are considerably higher than those of LNG (488,437 tons CO₂ e), which is in accordance with previous studies [8].

The difference between the emissions of HFO and LNG is partly due to the different processes considered in the life-cycle of each fuel and partly due to different parameters even in cases of similar processes. For example, comparing the emissions in the domain of transportation, not only the distances in which the LNG (~225 km) and HFO (~ 4700 km) are transported are different but also the modes of transportation for the fuels differ (e.g., LNG pipeline vs. HFO marine tankers). In the HFO life-cycles, the most GHG emission is related to the refinery stage (76%) whereas in the case of LNG, it is assigned to the liquefaction plant (40%).

For the sake of better comparison of the two fuels, the total emissions can be converted into monetary values. To this end, the British Colombia province carbon tax – defined as a tax based on GHG generation – which is 30 CAD per metric ton of CO₂ equivalent (in year 2012) is considered in the present study. The results have been presented as carbon tax in Tables 9 and 10. As can be noted, the carbon tax of HFO is about 17 times greater than that of LNG, making the latter a more economical (and cleaner) fuel than the former.

4.2. Comparison of safety risks

The probabilities assigned to the root nodes of the BNs and to the safety barriers of the ET for the hydrocarbon release scenarios are displayed in Tables 1-3 B (see Appendix B). These

probabilities are either extracted from the literature or estimated by subject matter experts [53-67]. By calculating the top event probabilities (hydrocarbon release) in each BN, the probabilities of the corresponding consequences can also be estimated. The risk of each consequence is then calculated as the product of the probability of the consequence and the envisaged loss values, expressed in monetary units. Table 11 presents the respective loss values used in the present study [59]. As the LCAs were conducted on an annual basis, for the sake of consistency, the risks were also estimated for one year.

The risks assessed for the LNG and HFO life-cycles are presented in Tables 12 and 13, respectively. As can be seen, LNG life-cycle has a significantly lower risk (~ 2.5 million CAD) than that of HFO life-cycle (~ 5.6 million CAD). In LNG life-cycle, the liquefaction (57.5%) and re-gasification (41%) processes contribute the most to the safety risk whereas in HFO life-cycle, the oil refinery (99.5%) accounts for nearly the entire safety risk, mostly due to the occurrence of major accidents such as fires and explosions. In Figure 7, the total amounts of losses, due to both the emissions and safety risks, of both fuels have been depicted. As can be seen, in terms of both emission and safety risk, LNG can be chosen as a safer and cleaner fuel. Regarding the HFO, the amount of safety risk does not compare to the amount of environmental emission (the safety risk is ~ 2% of the total losses); however, in the case of LNG, the safety risk accounts for about 17% of the total losses, which is quite notable.

Nevertheless, it should be noted that in the present study, the emissions that resulted from the combustion of fuels due to their accidental release, particularly fires and explosions, have been ignored due to the lack of relevant data about the volume of released fuel during each accident scenario.

5. Conclusions

In the present work, we introduced a methodology for risk-based life-cycle assessment (ARBLCA) of fuels, considering both environmental emissions and safety risks incurred during

the entire life-cycles of a product. For this purpose, the emissions of greenhouse gases to the atmosphere were calculated, converted into CO₂ equivalent, and then quantified to monetary values based on a carbon tax imposed by government. Likewise, the safety risks resulted from undesired releases of fuels and the ensuing fires and explosions were calculated using quantitative risk analysis techniques such as ET and BN throughout the processes involved in the life-cycle of fuels.

We exemplified the application of the methodology to LNG and HFO as the fuels of a fossil-fuel power plant in Newfoundland, Canada, so that the fuel with the lesser total loss can be determined. Considering the emissions and risks throughout the respective life cycles, it was demonstrated that not only is LNG by far a cleaner fuel than HFO (17 times less emissions), but also a safer alternative than HFO. In the present study, the inclusion of safety risks in the life-cycle risk assessment of LNG and HFO did not affect the preference of the fuels that could have been determined solely based on their environmental emissions. Nonetheless, it was demonstrated that in some cases, the safety risks can make a significant contribution to the total number of losses (e.g., about 17% in the case of LNG in this study) which in slightly different situations can lead to quite different priorities in deciding safer and/or cleaner fuel alternatives.

6. Acknowledgments

The second author (Khan) gratefully acknowledges the financial support provided by the Natural Sciences and Engineering Research Council (NSERC) of Canada, Canada Research Chair Program (Tier I) and the Research and Development Corporation (RDC) of Newfoundland and Labrador.

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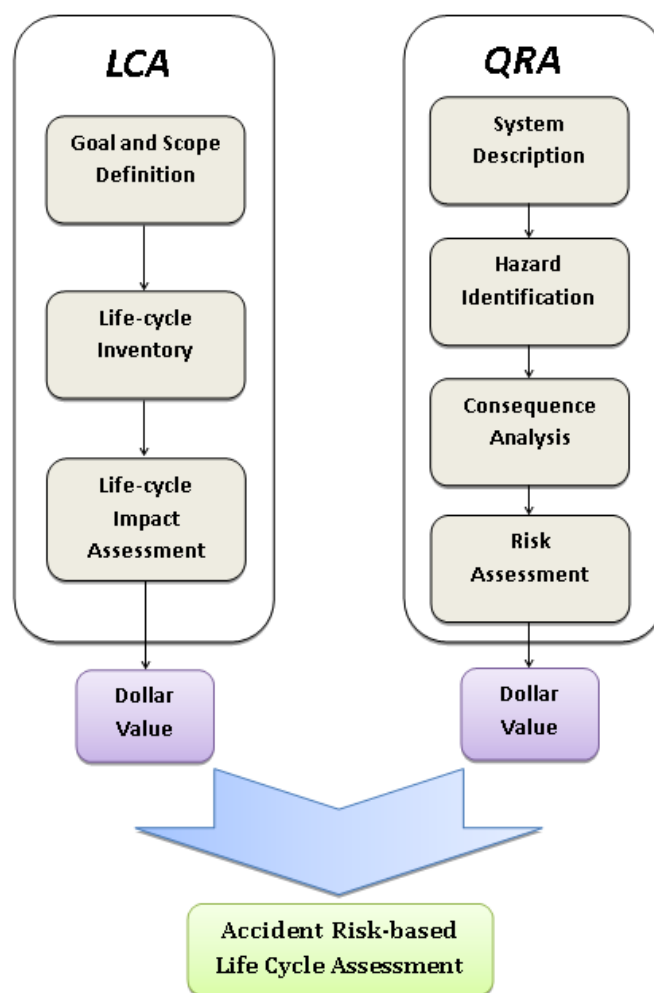


Figure 1. Accident risk-based life-cycle assessment diagram

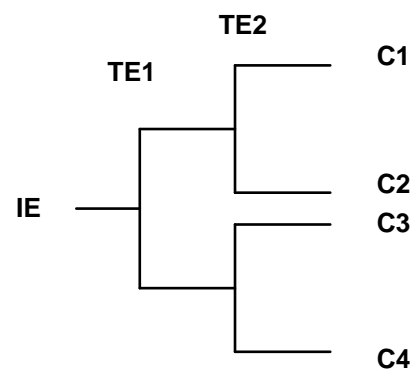


Figure 2. Event Tree

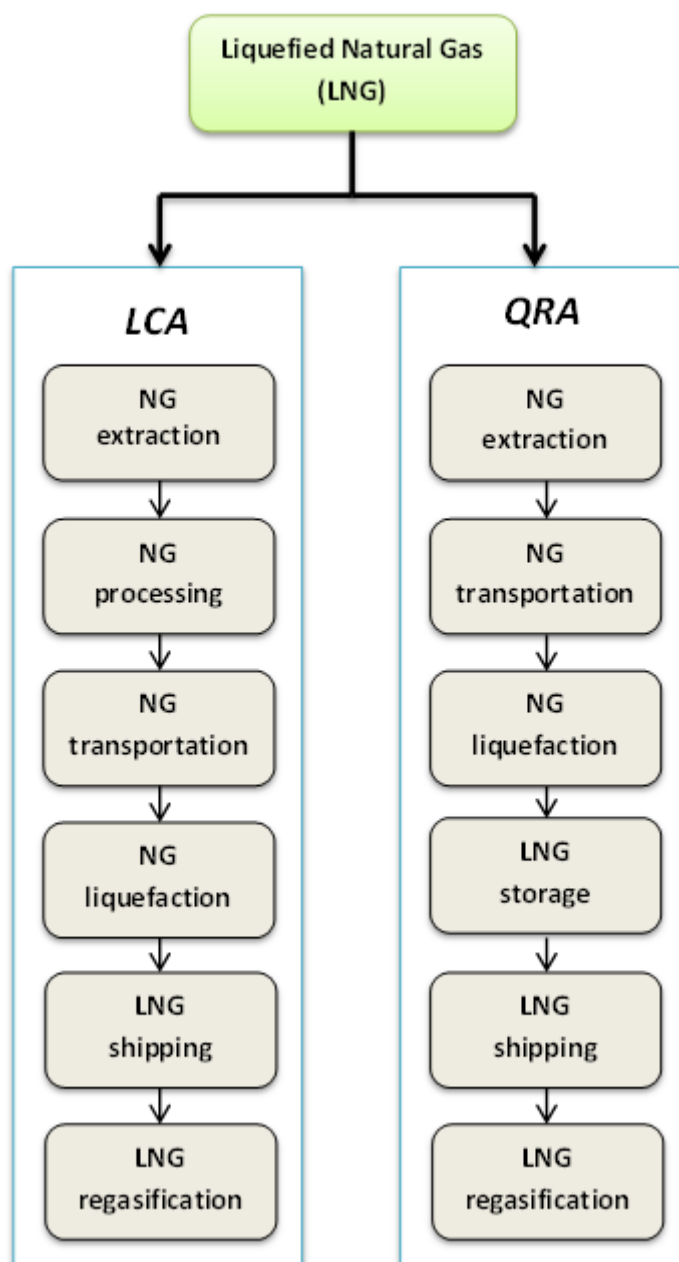


Figure 3. Accident risk-based life-cycle assessment of liquefied natural gas (LNG)

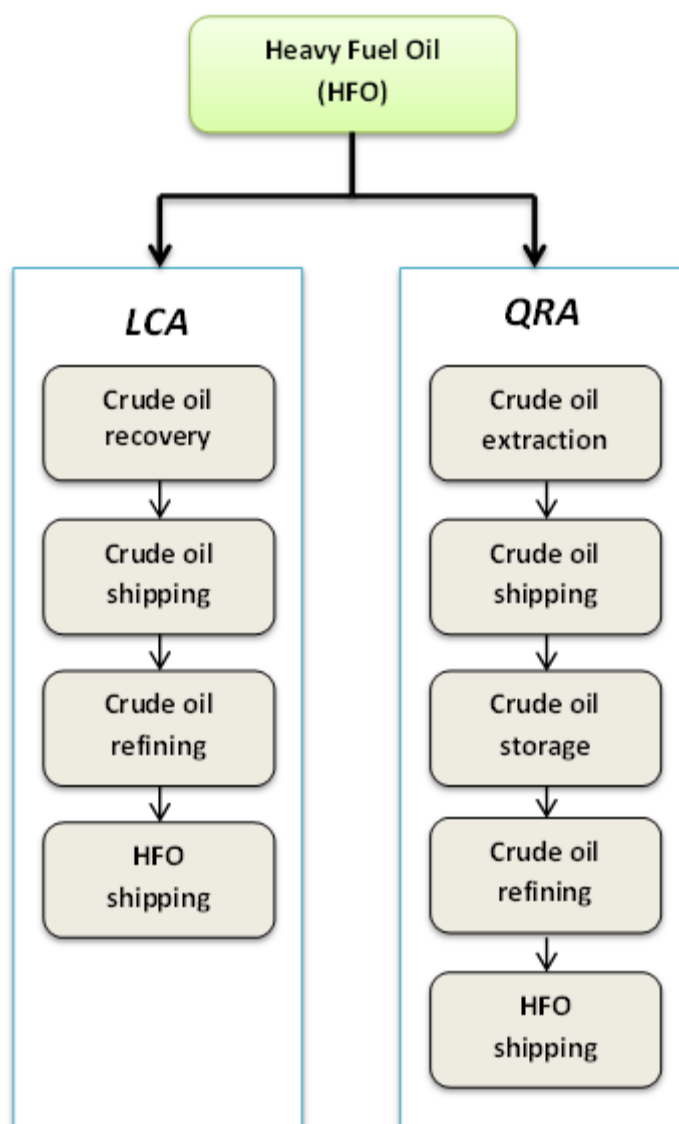


Figure 4. Accident risk-based life-cycle assessment of heavy fuel oil (HFO)

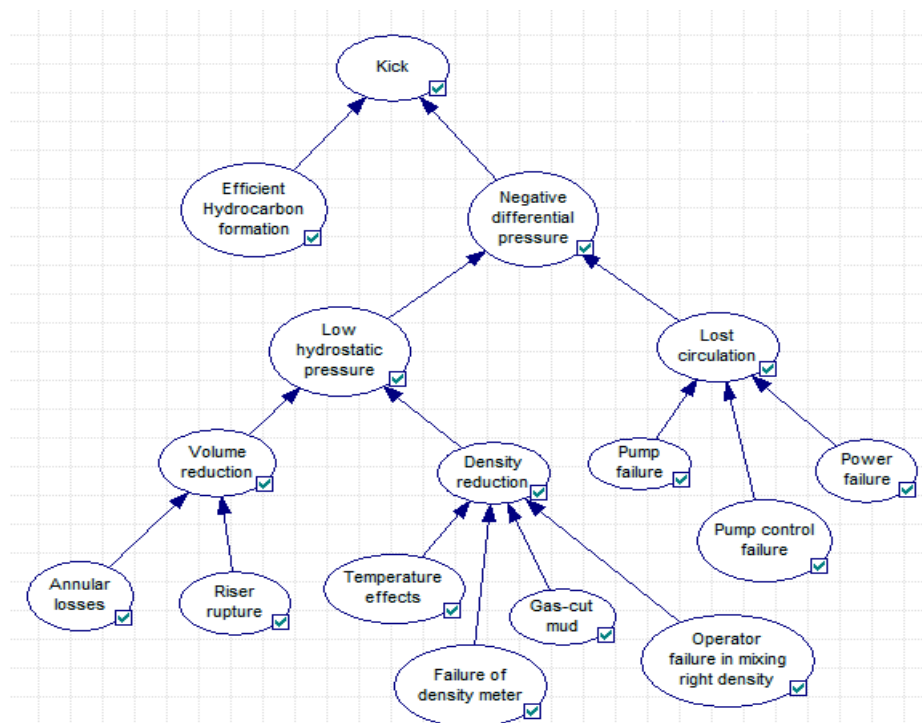


Figure 5. Undesired kick Bayesian network

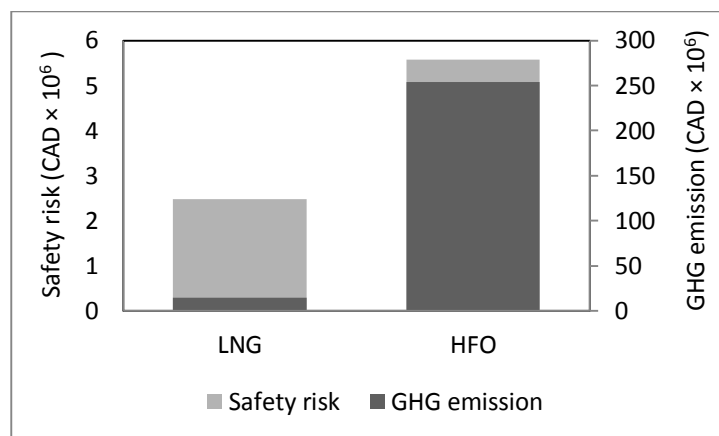


Figure 7. Comparison of life-cycle emissions and safety risks for LNG and HFO

APPENDIX (A)

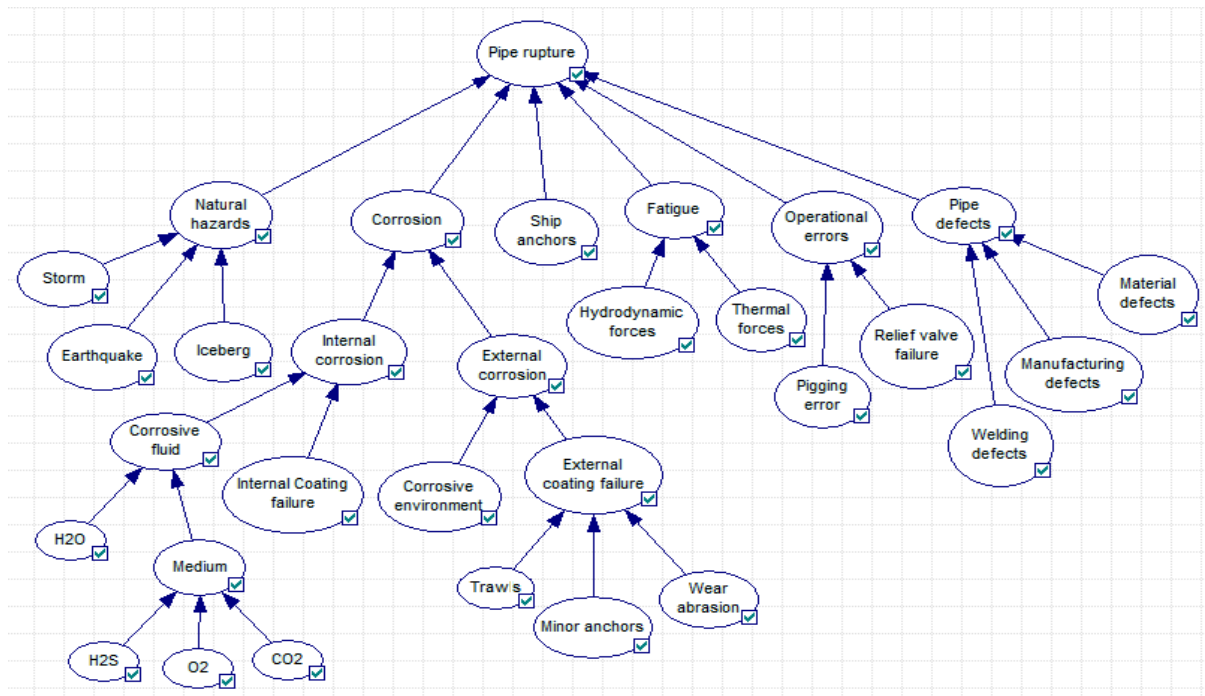


Figure A-1. BN of sub-sea pipe rupture

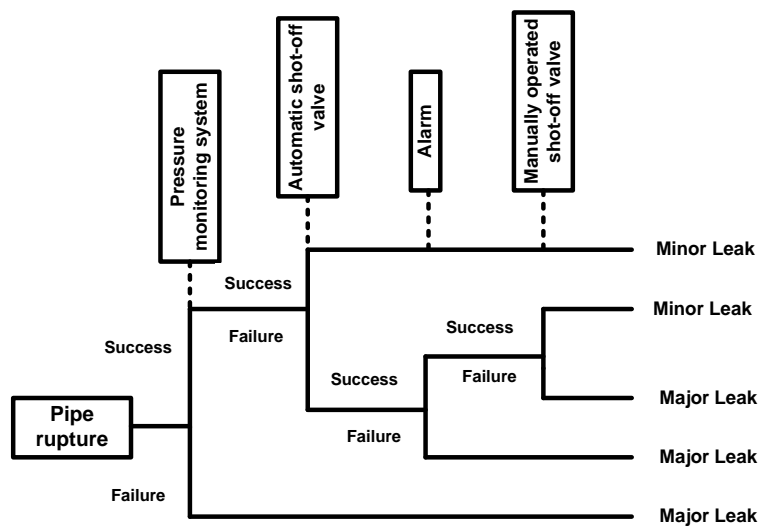


Figure A-2. Event tree of sub-sea pipe rupture

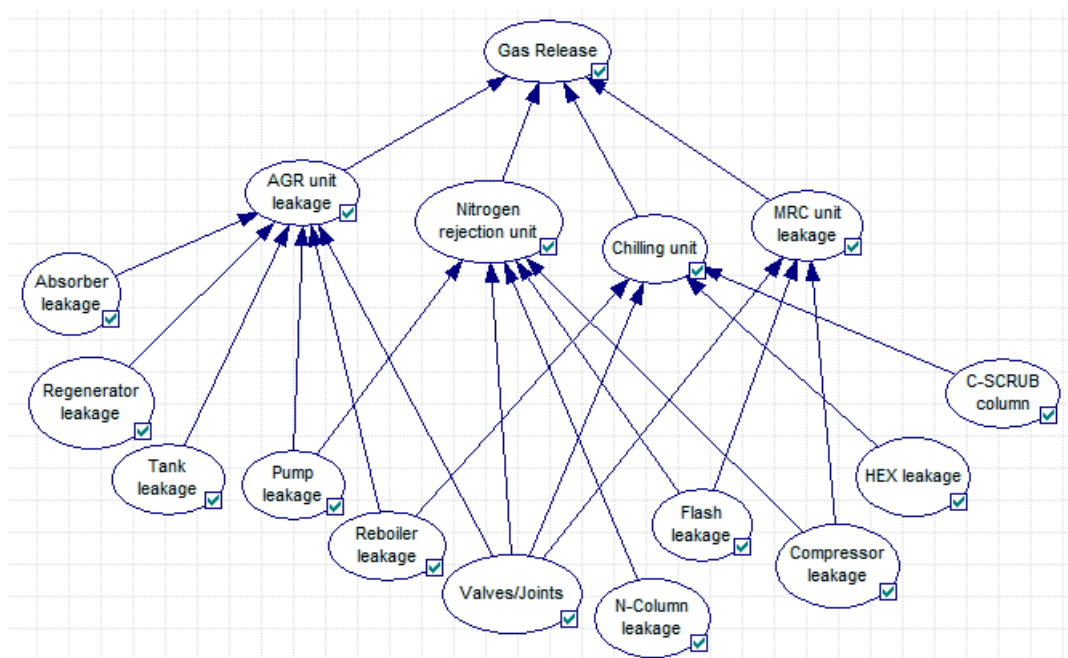


Figure A-3. Bayesian network of gas release in the liquefaction facility

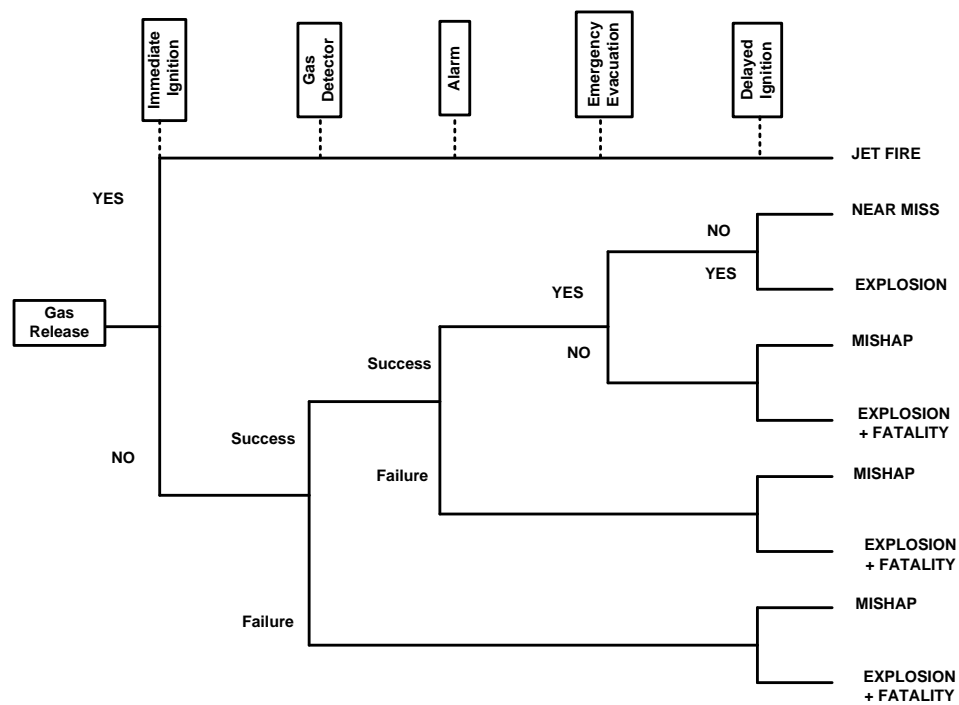


Figure A-4. Event tree of gas release in liquefaction facility

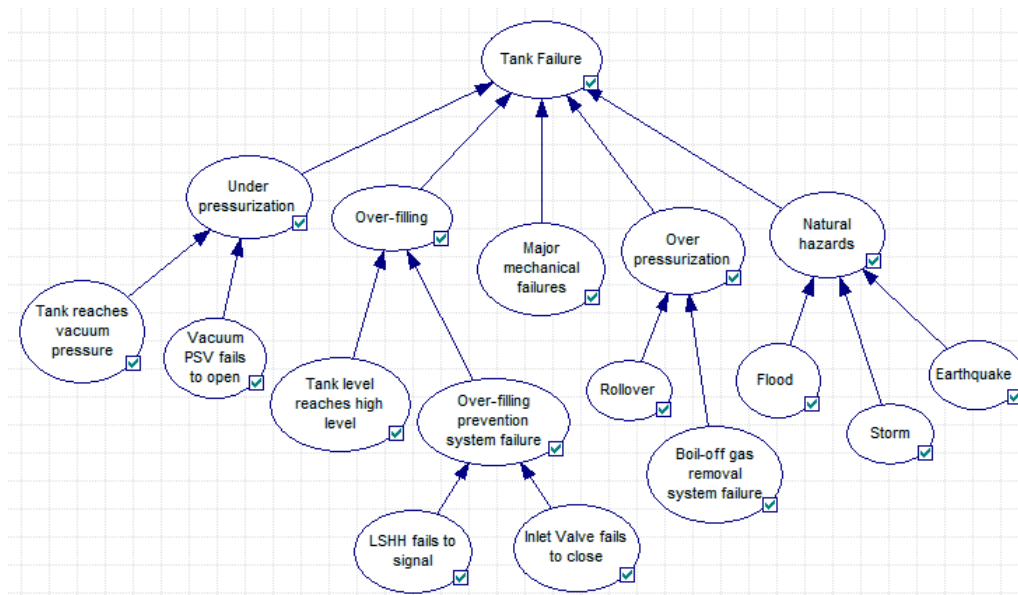


Figure A-5. Bayesian network of gas release from LNG storage tank

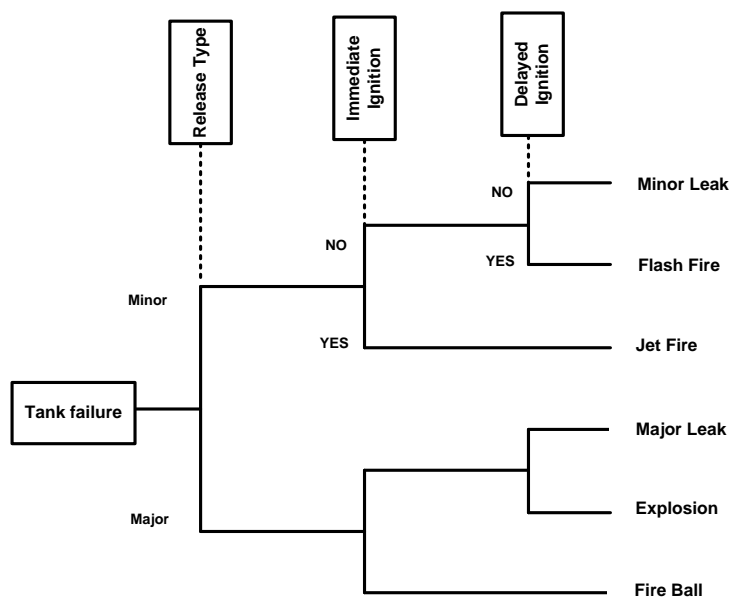


Figure A-6. Event tree of gas release in LNG storage tank

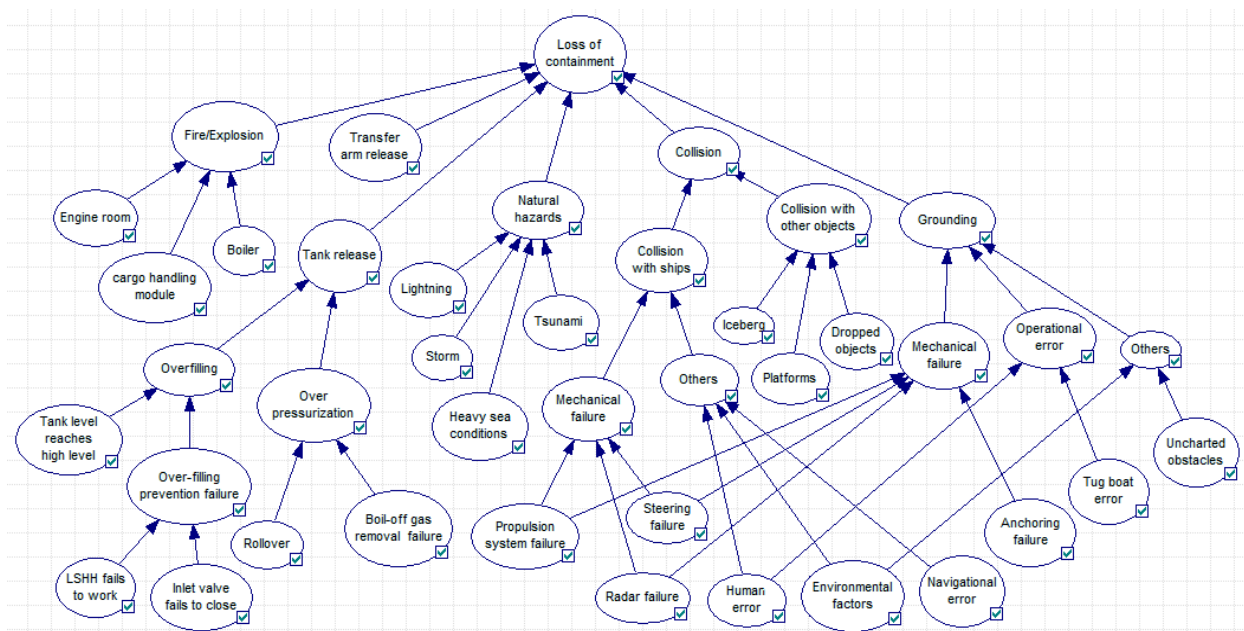


Figure A-7. Bayesian network for LNG release during shipping

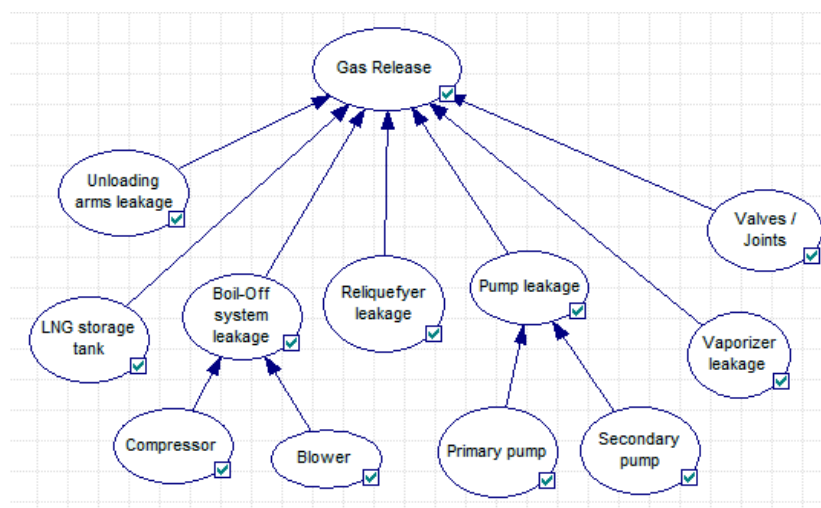


Figure A-8. Bayesian network for gas release during re-gasification process

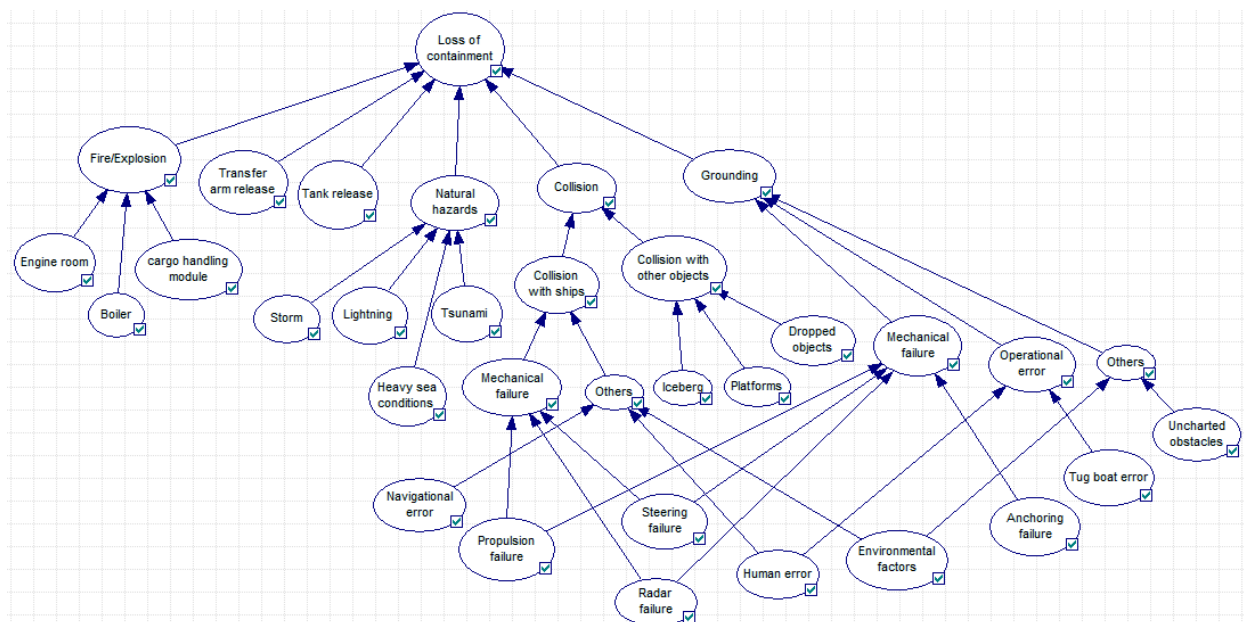


Figure A-9. Bayesian network for crude oil release during shipping

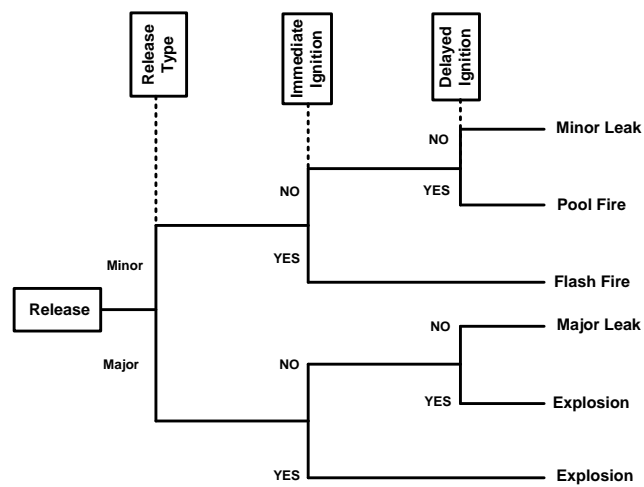


Figure A-10. Event tree analysis of crude oil release during shipping

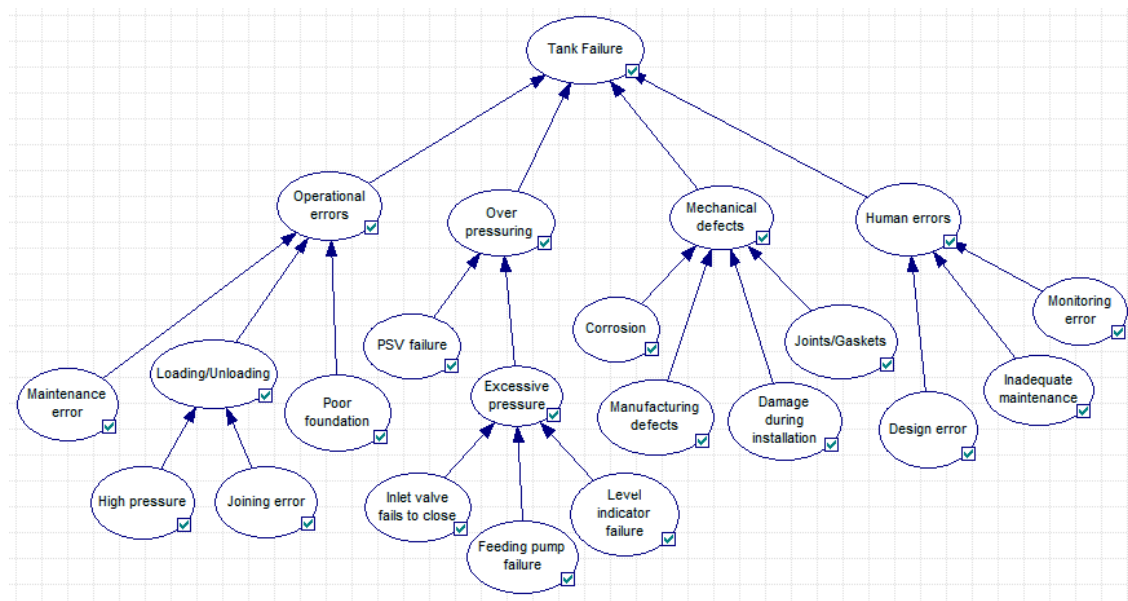


Figure A-11. Bayesian network of oil release from oil storage tank

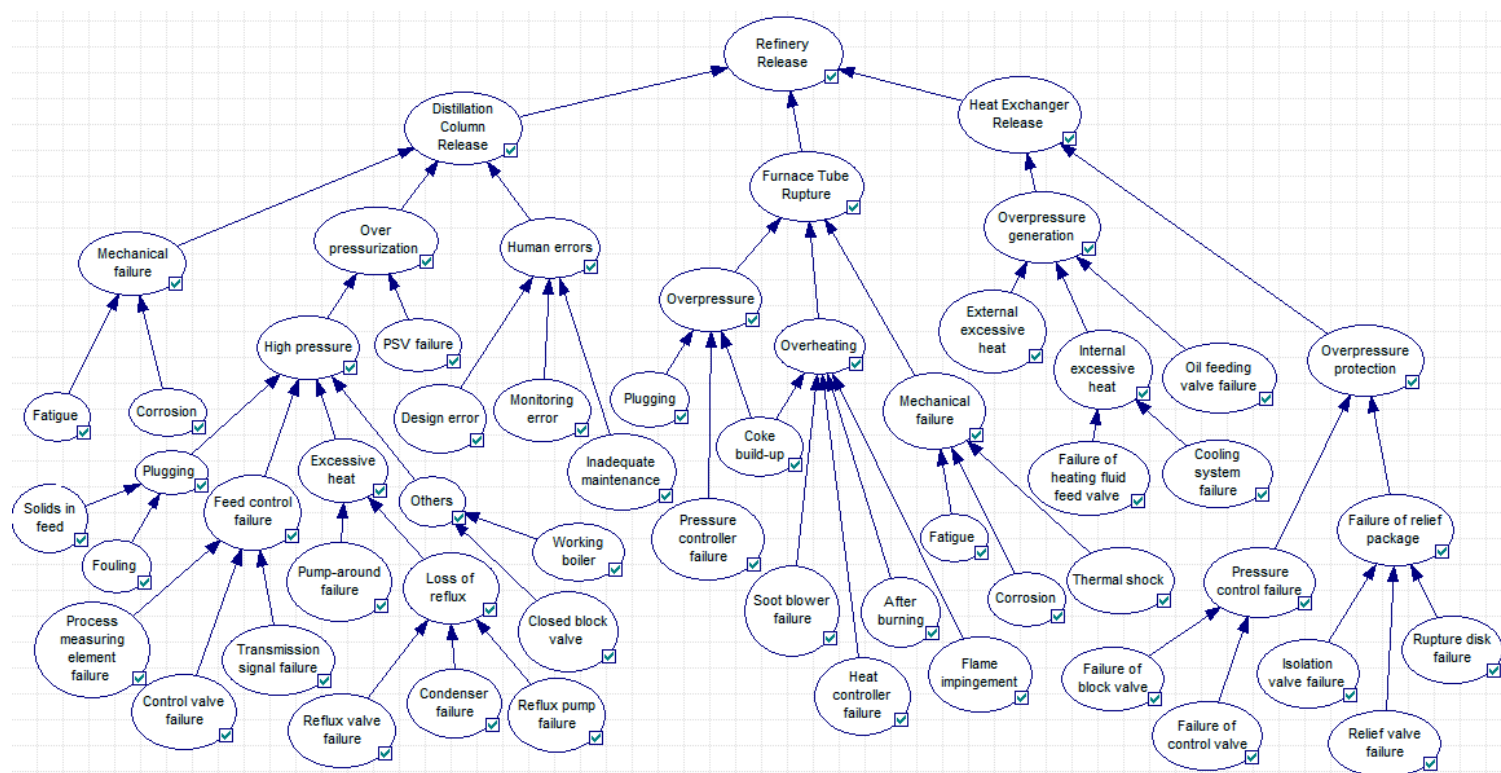


Figure A-12. Bayesian network of oil release in refinery

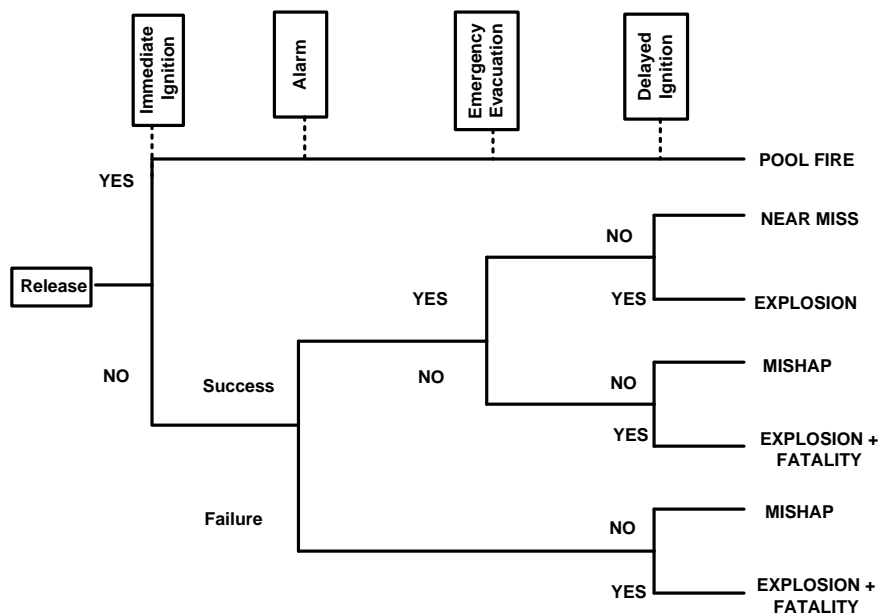


Figure A-13. Event tree analysis of oil release in refinery

Table 1. IPCC Global Warming Potentials

GHG	AR5 (IPCC 2013)	
	20-year	100-year
CO ₂	1	1
CH ₄	85	30
N ₂ O	264	265

Table 2. Emission factors for fugitive emissions during extraction

NG extraction emission source	Value	Unit
Fugitive emissions (captured for flaring)	3.90 E -05	kg CH ₄ /kg NG extracted
Fugitive emissions (not captured for flaring)	2.41 E -04	kg CH ₄ /kg NG extracted
Valve fugitive emissions (including pneumatic devices)	1.95 E -06	kg CH ₄ /kg NG extracted

Table 3. Unprocessed Natural Gas Flaring Emissions

Pollutant	Value	Unit
CO ₂	2.67	lb CO ₂ /lb flared NG
N ₂ O	8.95 E -05	lb N ₂ O/lb flared NG
CH ₄	1.53 E -02	lb CH ₄ /lb flared NG

Table 4. Emission factors for AGR process

Flow Name	Value	Unit
CO ₂ (combustion)	6.47 E -04	kg CO ₂ /kg NG product
CO ₂ (vented)	1.30 E -02	kg CO ₂ /kg NG product
N ₂ O	3.54 E -06	kg N ₂ O/kg NG product
CH ₄ (combustion)	1.27 E -05	kg CH ₄ / kg NG product
CH ₄ (vented)	9.71 E -04	kg CH ₄ / kg NG product

Table 5. Emission factors for dehydration

Flow Name	Value	Unit
CO ₂	4.24 E -04	kg CO ₂ /kg NG product
N ₂ O	2.26 E -09	kg N ₂ O/kg NG product
CH ₄ (combustion)	8.10 E -09	kg CH ₄ / kg NG product
CH ₄ (vented)	8.06 E -06	kg CH ₄ / kg NG product

Table 6. Centrifugal compressor emission factors

Pollutant	Value	Unit
CO ₂	8.80 E -02	kg CO ₂ /kg NG
CH ₄	6.89 E -06	kg CH ₄ /kg NG
N ₂ O	2.40 E -06	kg N ₂ O/kg NG

Table 7. Oil tanker specification

Average service speed	Maximum speed	Average main engine power	Average Aux engine power
14.7 Knots	16 Knots	9667 kW	2040 kW

Table 8. Emission factors of marine tanker (g/kWh)

Engine type	N ₂ O	CO ₂	CH ₄
Main (SSD)	0.031	622	0.006
Aux. (MSD)	0.031	692	0.004

Table 9. GHG emissions associated with LNG life-cycle.

Emission Source	Emission (Tons CO ₂ e)	Contribution (%)
NG Extraction	123,838	25
NG Processing	25,787	5
NG Pipeline	81,891	17
NG Liquefaction	192,000	40
LNG Carrier	4,920	1
Re-gasification	60,000	12
Total	488,437	
Carbon Tax (\$)	14,653,135	

Table 10. GHG emissions associated with HFO life-cycle.

Emission Source	Emission (Tons CO ₂ e)	Contribution (%)
Crude Oil Extraction	938,910	11
Crude Oil Processing	588,690	7
Venting, Flaring and Fugitives	441,450	5
Oil Tanker (oil field to refinery)	10,530	0.5
Oil Refinery	6,470,100	76
Oil Tanker (refinery to power plant)	10,500	0.5
Total	8,460,180	

Carbon Tax (\$)	253,805,400
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Table 11. Risk loss values and categories

Severity class	Dollar value (CAD)	Asset loss	Human loss	Environmental loss	Reputation loss
1	< 1 k	Not significant	No injury	No remediation required	Noticed by operating unit
2	1 K - 10 K	Short term production interruption	Minor injury, first aid attention required	Around the operating unit; easy recovery and remediation	Noticed in the operation line/ line supervisor,
3	10 K - 500 K	Damage of one unit, requiring repair; medium term production interruption	One injury, requiring hospitalization; no life threat	Around the operating line; easy recovery and remediation	Noticed in plant
4	500 K - 5 M	Damage of more than one unit' requiring repair/long term production interruption	More than one injury, requiring hospitalization; no life threat	Within plant; short term remediation effort	Local media coverage
5	5 M - 50 M	Loss of one operating unit/product	Multiple major injuries, potential disabilities, potential life threat	Minor offsite impact; remediation cost < 1 M	Regional media coverage; brief note on national media
6	50 M- 500 M	Loss of a major portion of facility/ product	One fatality and/or multiple injuries with disabilities	Community alerted; remediation cost < 5 M	National media coverage; brief note on international media
7	> 500 M	Total loss of facility/products	Multiple fatalities	Community evacuation; remediation cost > 5 M	National media coverage, asking for international aid

Table 12. Risks related to the LNG life-cycle

Stage	Risk (\$)	Contribution (%)
Drilling	13,334.36	0.5
NG Pipeline	10,527.42	0.4
NG Liquefaction	1,426,205.86	57.5
LNG Storage	50.82	0.002
LNG Shipping	6,652.77	0.3
Re-gasification	1,019,426.91	41
Total	2,476,198.17	

Table 13. Risks related to the HFO life-cycle

Stage	Risk (\$)	Contribution
Drilling	13,334.36	0.25
Oil Shipping	7,316.68	0.13
Oil Storage	17.60	0.0003
Oil Refinery	5,551,074.76	99.5
HFO Shipping	7,316.68	0.13
Total	5,579,060.11	

APPENDIX (B)

Table 1-B. Root causes probabilities used for LNG risk analysis.

No.	Root Cause	Probability	No.	Root Cause	Probability
Extraction			LNG Shipping		
1	Annular losses	1.00E-02	46	Engine room	9.50E-03
2	Riser rupture	1.00E-02	47	Cargo handling module	1.20E-04
3	Temperature effects	2.50E-03	48	Boiler	2.30E-04
4	Gas-cut mud	7.00E-03	49	Lightning	3.40E-02
5	Failure of density meter	2.00E-04	50	Heavy Sea Conditions	3.20E-03
6	Operator error in mixing density	3.00E-02	51	Storm	8.73E-02
7	Pump failure	4.00E-02	52	Tsunami	2.39E-02
8	Power failure	2.70E-04	53	Transfer Arm Release	7.80E-03
9	Pump control failure	1.00E-03	54	Propulsion system failure	7.00E-04

10	Efficient hydrocarbon formation	1.25E-01	55	Radar system failure	1.00E-03
NG Liquefaction			56	Steering system failure	5.20E-04
11	Absorber Leakage	2.00E-04	57	Human Error	1.30E-03
12	Regenerator Leakage	1.80E-03	58	Environmental factors	1.00E-03
13	Reboiler Leakage	3.00E-04	59	Navigational Error	4.10E-04
14	Pump Leakage	6.00E-03	60	Iceberg	2.32E-04
15	Valves/Joints	2.30E-04	61	Platforms	6.70E-05
16	Tank Leakage	1.00E-04	62	Dropped objects	2.80E-03
17	Compressor Leakage	1.40E-05	63	Anchoring Failure	3.20E-04
18	Flash Leakage	5.00E-04	64	Propulsion system failure	7.00E-04
19	HEX Leakage	1.00E-02	65	Radar system failure	1.00E-03
20	C-SCRUB Column	2.80E-05	66	Steering system failure	5.20E-04
21	N-Column Leakage	3.00E-03	67	Tug boat Error	1.20E-04
LNG Storage Tank			68	Uncharted obstacles	5.30E-04
22	Under Pressurization	2.90E-10	Gas sub-sea pipeline		
23	Tank reaches vacuum pressure	1.36E-05	69	Manufacturing defects	1.35E-04
24	Vacuum PSV fails to open	2.12E-05	70	Material defects	3.44E-03
25	Overfilling	1.20E-05	71	welding defects	1.08E-02
26	Tank level reaches high level	3.70E-04	72	Malfunction of relief valve	2.59E-04
27	LSHH fails to signal	1.00E-03	73	Pigging error	1.09E-02
28	Inlet Valve fails to close	3.14E-02	74	Thermal forces	4.20E-03
29	Major Mechanical Failures	8.80E-06	75	Hydrodynamic forces	5.16E-04
30	Over Pressurization	1.04E-03	76	Ship anchors	2.15E-03
31	Rollover	1.00E-03	77	Wear abrasion	8.53E-04
32	Boil-Off Gas removal failure	4.10E-05	78	Minor anchors	3.05E-02
33	Natural Hazards	1.33E-01	79	Trawls	4.11E-03
34	Flood	2.65E-02	80	Corrosive environment	1.00E+00
35	Earthquake	2.39E-02	81	Internal coating failure	2.41E-04
36	Storm	8.73E-02	82	CO2	2.22E-06
Re-gasification			83	O2	3.52E-06
37	Unloading Arms Leakage	3.40E-07	84	H2S	1.41E-05
38	LNG Storage Tank	2.00E-05	85	H2O	1.99E-05
39	Compressor	1.40E-05	86	Iceberg	2.32E-04
40	Blower	4.20E-04	87	Earthquake	2.39E-02
41	Re-liquefier Leakage	2.50E-04	88	Storm	1.69E-02
42	Primary Pump Leakage	6.00E-03			
43	Secondary Pump Leakage	6.00E-03			
44	Valves / Joints	5.00E-06			
45	Vaporizers Leakage	3.10E-03			

Table 2-B. Root causes probabilities used for HFO risk assessment.

No.	Root Cause	Probability
Oil Storage Tank		
1	Maintenance error	3.10E-02
2	High pressure	1.00E-04
3	Joining error	4.60E-03
4	Poor foundation	2.40E-05
5	PSV failure	2.59E-04

6	Inlet valve fails to close	2.06E-04
7	Feeding pump failure	5.00E-04
8	Level indicator failure	1.70E-05
9	Corrosion	2.00E-03
10	Manufacturing defects	1.20E-05
11	Damage during installation	4.30E-03
12	Joints/gaskets	2.30E-04
13	Design error	1.30E-05
14	Inadequate maintenance	1.20E-03
15	Monitoring error	3.40E-03
Oil Refinery		
16	Solids in feed	4.20E-05
17	Fouling	6.50E-04
18	Process measuring element failure	1.76E-03
19	Control valve failure	2.80E-05
20	Transmission signal failure	1.70E-03
21	Pump-around failure	5.00E-04
22	Reflux valve failure	2.80E-05
23	Condenser failure	2.19E-04
24	Reflux pump failure	5.00E-04
25	Closed block valve	3.98E-04
26	Working boiler	2.60E-04
27	Design error	1.30E-05
28	Inadequate maintenance	1.20E-03
29	Monitoring error	3.40E-03
30	PSV failure	2.59E-04
31	Fatigue (Column)	1.50E-04
32	Corrosion (Column)	2.00E-03
33	External excessive heat	1.54E-04
34	Failure of heating fluid feed valve	2.06E-04
35	Cooling system failure	2.19E-04
36	Failure of oil feeding valve	2.06E-04
37	Failure of block valve	3.98E-04
38	Isolation valve failure	5.90E-05
39	Relief valve failure	2.59E-04
40	Rupture disk failure	3.30E-04
41	Plugging	3.16E-02
42	Pressure controller failure	1.76E-03
43	Coke build-up	5.10E-02
44	Heat controller failure	2.50E-04
45	Soot blower failure	1.40E-04
46	Flame impingement	4.20E-03
47	After burning	3.60E-03
48	Fatigue (Furnace)	1.57E-04
49	Corrosion (Furnace)	1.90E-04
50	Thermal shock	2.40E-03

Table 3-B. Safety barrier probabilities used in event trees.

ID	Safety Barrier	Probability
1	Minor release	8.00E-05
2	Major release	1.00E-04
3	Immediate ignition	1.00E-01
4	Delayed ignition	3.00E-01
5	Gas detector failure	4.00E-02
6	Emergency evacuation	2.00E-01
7	Pressure monitoring	1.00E-03
8	Automatic shot-off valve	1.00E-02
9	Alarm	1.00E-02
10	Manual shot-off valve	3.00E-02
11	Kick non-detection	8.60E-06
12	Lower pipe ram	1.00E-04
13	Upper pipe ram	1.00E-04
14	Blind/shear ram	1.00E-04
15	Annular preventer	1.00E-04
16	Casing	2.00E-04