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CURRENT STATUS AND PROSPECTS FOR LNG IN THE UNECE REGION

CHAPTER TWO: LNG VALUE CHAIN

1. Introduction

This chapter depicts the major components of the liquefied natural gas (LNG) value chain. The LNG value chain consists of facilities, technologies, capital investments, and commercial mechanisms that enable gas to move from the wellhead to overseas markets.

Information is presented in the following subsections:

- Introduction – overview, definitions and history
- LNG value chain segments – descriptions of the major steps in the chain, including gas supplies - conventional, unconventional/shale – issues & resources - liquefaction, shipping & Storage, regasification and new tech - FSRU
- Commercial mechanisms, price formation, business models, contracting practices, risks
- Unique and emerging uses of LNG, including peak-shaving, gas distribution to remote communities, LNG vehicles – Blue Corridors, Clean Energy Fuel (US) – and using LNG to balance intermittent renewable energy sources

The goal is to provide a common database of information related to the LNG value chain so that there is a common understanding of the industry, how it is structured, how it operates, and what it accomplishes.

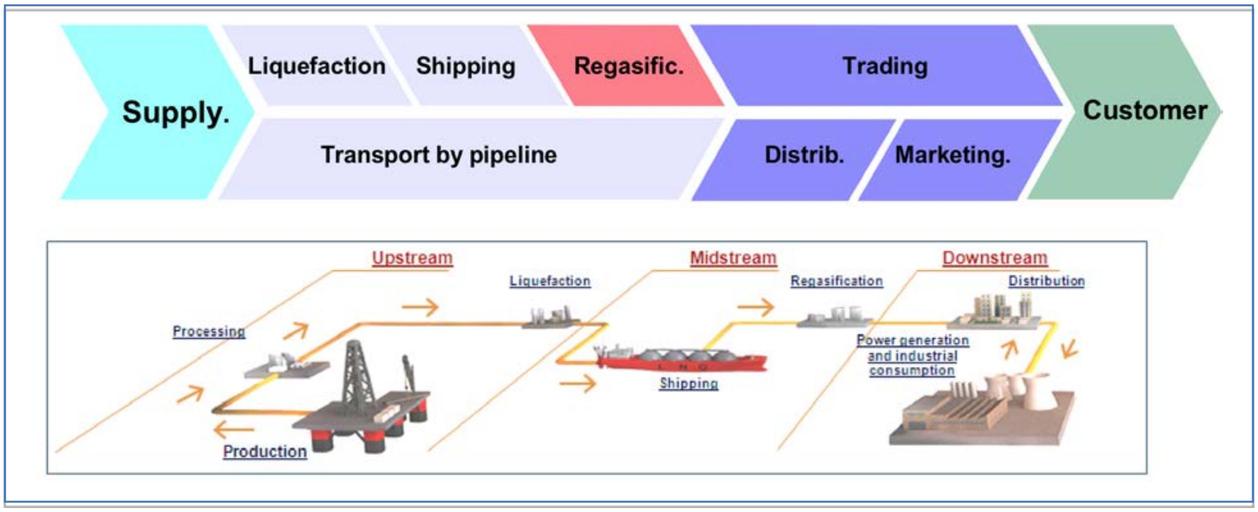
1.1. Definition of the LNG value chain

In general, there are two basic ways to transport the natural gas from producing reservoirs to final consumers:

- Through a pipeline, with no change in the gas phase
- Via the LNG value chain, i.e., in a liquid phase.

The LNG value chain consists of a number of segments (or links in the chain) that are largely distinct from transportation via pipelines. As illustrated in Figure 1, and as more fully described in further sections of this chapter, the major segments include:

Figure 1 – Illustrations of LNG and Pipeline Value Chains



- Supply. Production, processing and initial transportation processes are the same as if gas will be transported to market via pipeline. Gas is produced at the wellhead and transported locally via gathering and pipeline systems from gas fields to the liquefaction plant and terminal.

- Liquefaction. Gas is chilled to minus 161 degrees Celsius, at which natural gas becomes a liquid at atmospheric pressure, and shrinks in volume to approximately one 600th of its gaseous phase. The resulting liquefied natural gas (LNG) is stored as a liquid in cryogenic tanks before shipping.

- Shipping. LNG is received aboard tankers where it is stored cryogenically (as above), and is transported overseas to receiving terminals, where it is regasified for use in local end-use markets. In smaller scale operations, cryogenically capable trucks, rail cars or barges are used to transport LNG.

- Regasification. At regasification terminals, LNG is received and stored cryogenically in it liquid phase. The LNG is then warmed, or vaporized, and the resulting natural gas is injected into pipelines for delivery locally to end-users.

- Trading. At points throughout the foregoing chain, market participants, i.e., buyers and sellers, undertake trading activities aimed at ensuring LNG is moved to markets in the necessary volumes at economical commercial terms. Traders engage in both physical and financial trading in order to optimize LNG movements and reduce commercial risks.

- Market technologies. Just as for pipeline gas, regasified LNG is distributed through local gas pipeline networks to end-users, who receive and consume it in a form that is indistinguishable from natural gas at the burner tip.

Storage is not listed as a separate step above because LNG is stored cryogenically throughout the value chain, i.e., at liquefaction terminals, aboard LNG carriers, and at receiving/regasification terminals. As discussed later in this chapter, LNG may also add considerable value when it is stored (as LNG) at points within conventional gas distribution systems and at end-use locations.

1.2 History

Major milestones in development of the modern LNG industry are listed in the box, inset at right. The process of cooling natural gas dates from the 19th century when the British chemist and physicist Michael Faraday experimented with liquefying different types of gases, including natural gas. German engineer Karl Von Linde built the first practical compressor refrigeration machine in Munich in 1873.

The first LNG plant was built in West Virginia in 1912 and began operation in 1917. The first commercial liquefaction plant was built in Cleveland, Ohio, in 1941.

The possibility of transporting LNG to distant destinations became reality in January 1959. The world's first LNG tanker, *The Methane Pioneer*, a converted Liberty freighter from World War II containing five 7,000-barrel aluminum prismatic tanks, carried an LNG cargo from Lake Charles, Louisiana (US), to Canvey Island, United Kingdom. This event demonstrated that large quantities of liquefied natural gas could be transported safely across the ocean.

Major LNG milestones:

- 1938: first LNG peak shaving plant in US
- 1959: first international LNG cargo (Methane Pioneer) from US Gulf to UK (Canvey Island regasification terminal)
- 1964: first liquefaction plant in Africa (Algeria)
- 1969: first deliveries of LNG in Japan from Kenai (Alaska)
- 1972: first LNG liquefaction plant in Asia (Brunei)
- 1977: first LNG liquefaction plant in the Middle East (Abu Dhabi)

Figure 2 – First LNG cargo ship, the Methane Pioneer


The Methane Pioneer tanker

Following the successful performance of The Methane Pioneer, shown in Figure 2 over the next 14 months, seven additional cargoes were delivered with only minor problems.

The British Gas Council proceeded with plans to implement a commercial project to import LNG from Venezuela to Canvey Island. However, before the commercial agreements could be finalized, large quantities of natural gas were discovered in the Sahara, closer to England than Venezuela.

In 1961, Britain signed a 15-year contract to take less than 1 million tonnes per annum (mtpa) from Algeria, commencing in 1965. The first liquefaction plant in the world was commissioned at Arzew in Algeria. The United Kingdom became the world's first LNG importer and Algeria the first LNG exporter. The following year the French signed a similar deal to buy LNG from Algeria.

In 1969, the first exports of LNG from the United States to Asia began with deliveries from Alaska's Kenai plant to Japan's Tokyo Gas and Tokyo Electric Power Company (Tepco).

Libya's plant at Marsa el Brega began deliveries to Spain in 1970 and also later to Italy.

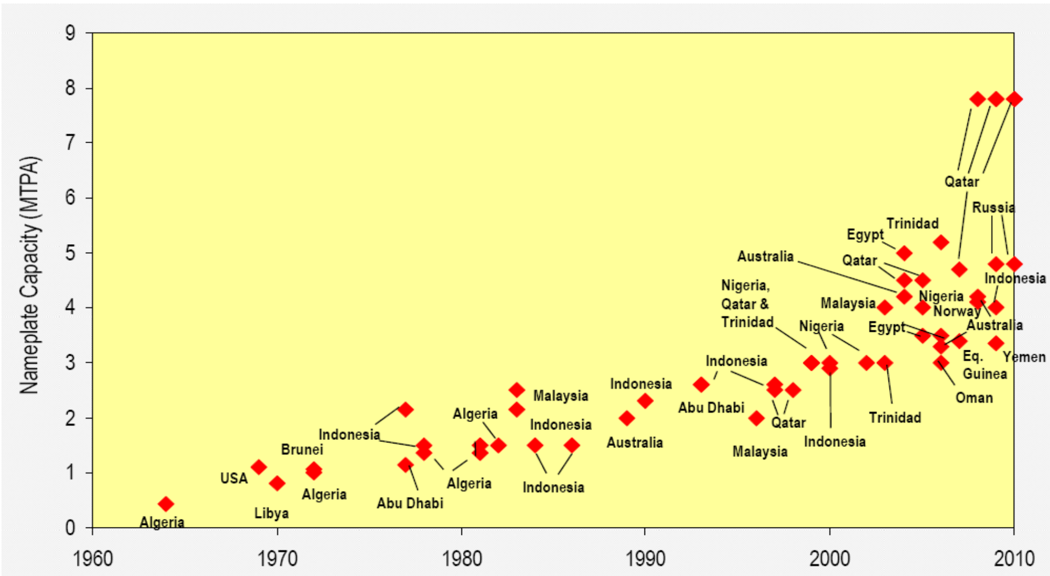
U.S. imports from Algeria were approved in 1972, and consequently, between 1971 and 1980, four LNG import terminals were built in the United States, located at Lake Charles (Louisiana); Everett (Massachusetts); Elba Island (Georgia); and Cove Point, (Maryland). LNG imports declined in 1979, affected by price disputes and a gas surplus.

In 1972, Brunei became Asia's first producer, bringing on stream an LNG plant at Lumut and supplying Korea and Japan.

The LNG market has continued growing rapidly in Europe and Asia, with new suppliers entering in operation in the next years: Abu Dhabi (EAU) started the LNG production in 1977 as the first producer in the Middle East, Indonesia also in 1977, Malaysia in 1983, Australia in 1989, Qatar in 1997, Trinidad and Nigeria in 1999, Oman in 2000, Egypt in 2004, Equatorial Guinea in 2007, Russia in 2008, Yemen in 2009 and Peru expected for 2010.

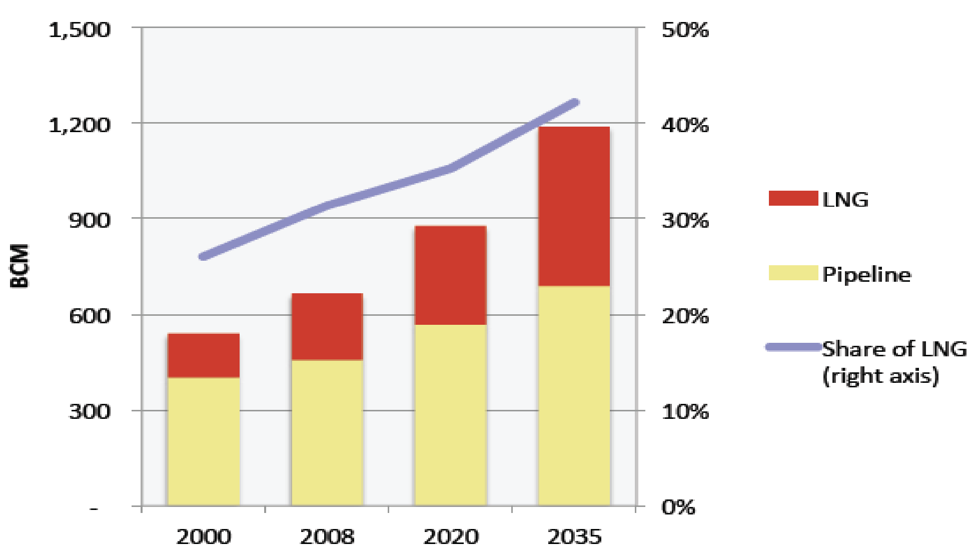
The scale of LNG projects has increased dramatically over the past 4 decades, as shown in Figure 3, e.g., each one of the most recent Qatari liquefaction trains is some 20 times the scale of the first Algerian train.

Figure 3 – History of LNG Liquefaction Plants



LNG accounted for 9.4% of the world's natural gas demand in 2010.[1] The global trade in LNG, which increased at a rate of 7.4 percent per year over the decade from 1995 to 2005, is expected to continue to grow substantially during the next few decades, as shown in IEA's current forecast (see Figure 4).

Figure 4 – IEA Projection of Rising LNG Global Trade



[1] BP 2011 Statistical Review.

2. Segments in the LNG Value Chain

The major segments in the LNG value chain are described in this section. While some segments are also concerned with pipeline transportation (e.g., gas supplies and consumption), the focus below is on elements that critically support or depend on LNG, e.g., gas demand in Asia Pacific markets, surplus shale gas production in the United States, and, of course, liquefaction, shipping and regasification.

2.1. Gas Resources and Reserves

2.1.1. Definitions

Measurements of natural gas that may be produced in the future take two basic forms – reserves and resources, sometimes referred to as proved versus potential reserves. These concepts are defined as follows:

- Gas reserves (or proved reserves) consist of natural gas that is anticipated to be commercially recoverable from known accumulations from a given date forward.

- Gas resources consist of all other gas known or believed to exist, i.e., concentrations in the earth's crust of naturally occurring gaseous hydrocarbons that can conceivably be discovered and recovered. Normal use encompasses both discovered and undiscovered resources.

Gas reserves are often expressed in terms of probabilities, i.e., the chance that a specified volume of gas exists or not, on a numeric scale ranging from zero (impossibility) to 100% (absolute certainty). Under this system, proved reserves are restricted to gas as above with a probability of 90% or better (p90 to p100), and for which pipeline infrastructure either exists or is approved, with construction underway or imminent. Other gas volumes are either probable or possible (p50) or speculative (p10).[2]

Each of the foregoing categories has a particular meaning within the gas industry. For determining immediately productive gas fields, p90 or p100 gas reserves are of crucial importance. For long-term forecasting of gas supplies, however, p50 gas is more important because it is substantially this gas which will be in production in a decade or two, along with today's p90 and p100 gas. Even p10 gas has a meaning because it may indicate the direction of drilling efforts in the future.

[2] For further definitions and information, see Guidelines for Application of the Petroleum Management System, sponsored by Society of Petroleum Engineers (SPE) American Association of Petroleum Geologists (AAPG) World Petroleum Council (WPC) Society of Petroleum Evaluation Engineers (SPEE) Society of Exploration Geophysicists (SEG), November 2011.

Economics and technology play a major part in determining volumes of gas in each of the foregoing categories. For example, as unconventional gas extraction technologies have improved in the past decade, gas reserves and resource estimates have grown accordingly; in other words, with knowledge that new, economic technologies exists to extract shale gas, more of it is likely to be produced.

2.1.2. Global Gas Reserves

The total level of proved conventional gas reserves in the world reached more than 187,1 Tcm at the end of 2010[3]. Comparing it with total gas demand of 3,19 Tcm, we can conclude that there are enough proved gas reserves for the next 59 years even in the essentially impossible case of no additional discoveries, being higher than the proved oil reserves (48 years) in terms of current annual consumption levels.

Conventional global gas and oil reserves and production are summarized in Table 1 and Table 2:

Table 1 – Global Gas Reserves and Production, 2010

	Gas Proved Reserves (Tcm)	Gas Production (Bcm)	Ratio	LNG Production (Bcm)	Ratio (*)
North America	9.9	826.1	12.0	1.6	618.8
S. & Cent. America	7.4	161.2	45.9	22.2	33.3
Europe & Eurasia	63.1	1043.1	60.5	18.7	337.4
Middle East	75.8	460.7	164.5	100.6	75.3
Africa	14.7	209	70.3	58.4	25.2
Asia Pacific	16.2	493.2	32.8	96.1	16.9
TOTAL	187.1	3193.3	58.6	297.6	62.9
(*) Hypothesis: LNG represents 10% of total gas production.					

Source: Appendices.

Table 2 – Global Oil Reserves and Production, 2010

	Oil Proved Reserves K Mt)	Oil Production (Mt)	Ratio
North America	10.3	648.2	15.9
S. & Cent. America	34.3	350.0	98.1
Europe & Eurasia	19.0	853.3	22.3
Middle East	101.8	1184.6	85.9
Africa	17.4	478.2	36.3
Asia Pacific	6.0	399.4	14.9
TOTAL	188.8	3913.7	48.2

Source: Appendices.

3 Data in this sub-section derived from 2011 BP Statistical Review.

For perspective, a conventional liquefaction facility tending to operate for 25 years will require around 1,37 Tcf per mtpa of capacity.

As was shown in Table 1, nearly three quarters of the world's proved natural gas reserves (74.2%) lies in the Middle East and Europe & Eurasia, the latter mostly in the Russian Federation. Nearly all of this gas is considered to be conventional, including gas from onshore and offshore fields.

Thus, as a point of departure, while unconventional gas has received so much attention lately because of rapidly growing estimates – especially in the U.S., China and Australia, most of the world's proved gas reserves (i.e., that has been discovered and is remaining to be produced) consist of gas that will be extracted by conventional means. In other words, the world's unconventional gas supplies from tight sands, coal seams and shale beds lie largely beyond today's conventional reserves.

2.1.3. Unconventional Gas

Gas that is extracted economically from rotary drilling rigs without stimulation is loosely referred to as conventional. Historically, conventional natural gas deposits have been the most practical, and easiest, deposits to mine although as technology and geological knowledge advances, gas production is increasing rapidly from reservoirs once considered economically and technically impossible to develop.

Unconventional gas consists of gas that must be extracted from the ground by means other than conventional rotary rigs. The following features characterize unconventional gas:[4]

- Unconventional gas formations are "continuous", deposited over large areas rather than in discrete traps.
- The geologic setting of unconventional gas is several orders more complex than conventional gas.
- For coalbed methane and gas shales, the gas source, trap and reservoir are the same, not three distinct elements as for conventional gas.

Thus, unconventional gas is entrained in underground seams where the permeability of the surrounding rock is too low to permit standard drilling techniques. Producing firms must exploit these reserves using extraction technologies that more resemble mining processes. Methods used to produce unconventional gas include directional drilling into seams together with high pressures injection of water and sand mixtures in order to break up, or fracture, the surrounding rock seams and free the trapped natural gas.

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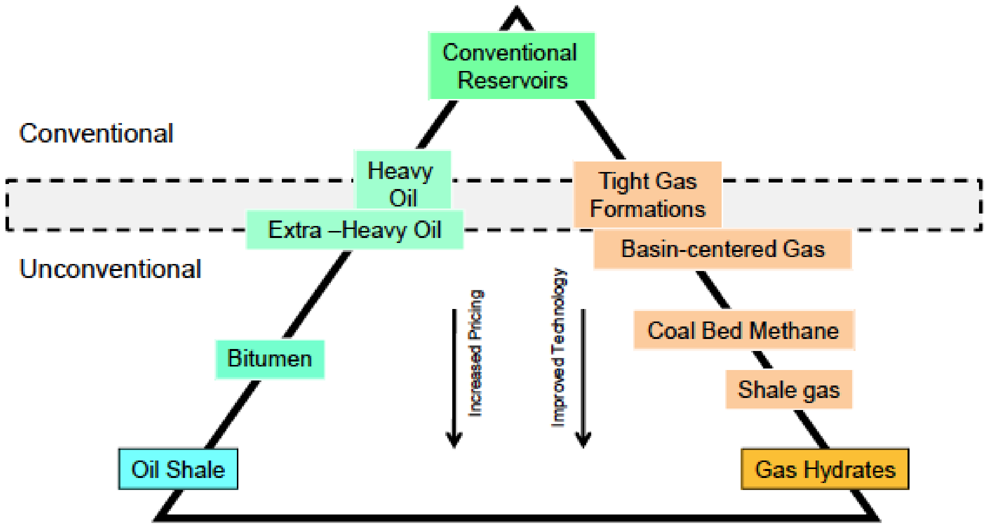
[4] V. Kuuskraa, Advanced Resources International, Arlington, VA, USA, March 2010.

Figure 5 – Conventional and Unconventional Gas Resources



(modified from Holditch, JPT Nov. 2002)

There are four main types of unconventional gas resources: tight gas, coal bed methane (CBM), shale gas, and gas hydrates, each with increasingly sophisticated production technologies (see Figure 5).[5]

Exploitation of shale gas resources involves drilling numerous horizontal wells from a single location on the surface, followed by fracturing the rock at multiple intervals, a process that requires vast quantities of water. Further information on North American shale gas drilling technologies and developments is discussed later in this section.

Unconventional natural gas deposits are beginning to make up an increasing portion of overall gas supplies. This is particularly true in North America, where unconventional gas (tight seam gas, shale and coal-bed methane, CBM) comprised 64% of US gas production in 2011, and appears soon headed to two-thirds. Composition of unconventional gas has historically been quite lean, which is adequate for U.S. pipeline specifications, e.g., CBM is 94-98% methane.

In summary, unconventional gas resources, while largely unproved, are vast and their costs of production are decreasing.

2.1.4. Shale Gas in North America

The most visible and prolific unconventional gas developments in the past decade within the UNECE region (and beyond) have taken place in shale gas fields of North America, where shale gas resource base is widely distributed and substantial, production costs have fallen and volumes have risen quickly.

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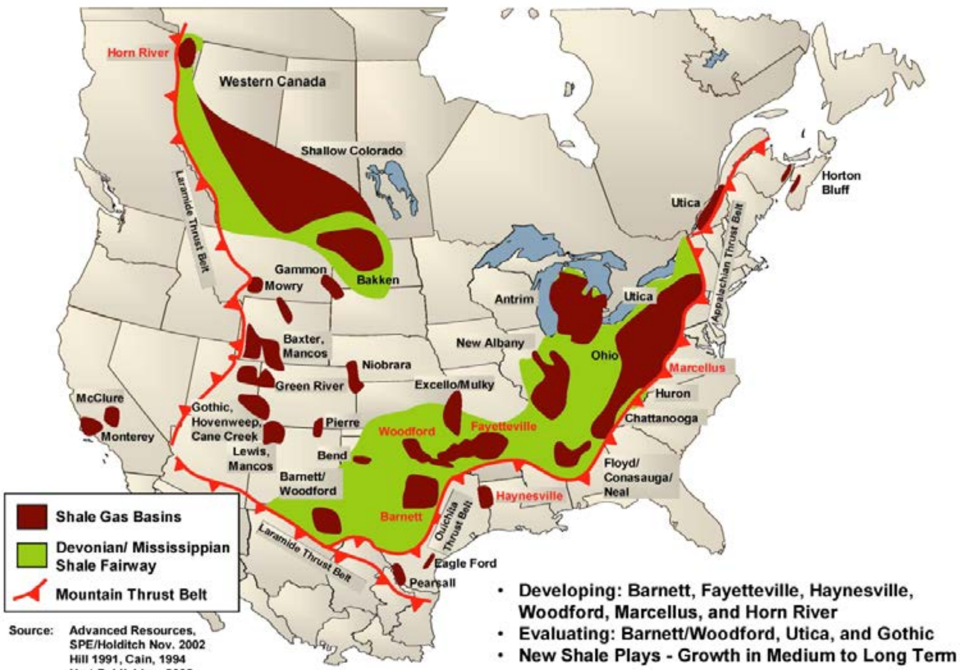
[5] Ibid.

Major North American shale gas fields include the following, roughly in order of development since 2002 (see Figure 6):

- Barnett and Eagle Ford in Texas
- Haynesville, Fayetteville, Cana, Arkoma-Woodford (Alabama/Oklahoma/Arkansas)
- Granite Wash in Oklahoma and the Texas Panhandle
- Horn River and Montney in British Columbia, Canada
- Marcellus and Utica in Pennsylvania, West Virginia, Ohio, New York and Quebec
- Bakken, Spanish, Three Forks in North Dakota and Saskatchewan
- Niobara in Colorado.

Figure 6 – Map of US and Canadian Shale Gas Resources



Unconventional (tight sands) gas development is also proceeding in the U.S. using similar technologies in the Uinta, Green River and Piceance Basins in Wyoming, Utah and Colorado, as well as the Bossier Sands in East Texas.

The data in Table 3 illustrate the considerable gap between proved reserves of shale gas (which totaled less than one Tcm at year end 2008) and potential resources of shale gas, which were estimated in 2010 to be nearly 97 Tcm. As shale development activities continue to evolve, an increasing volume of the potential resource will be reclassified as proved (p100 or p90).

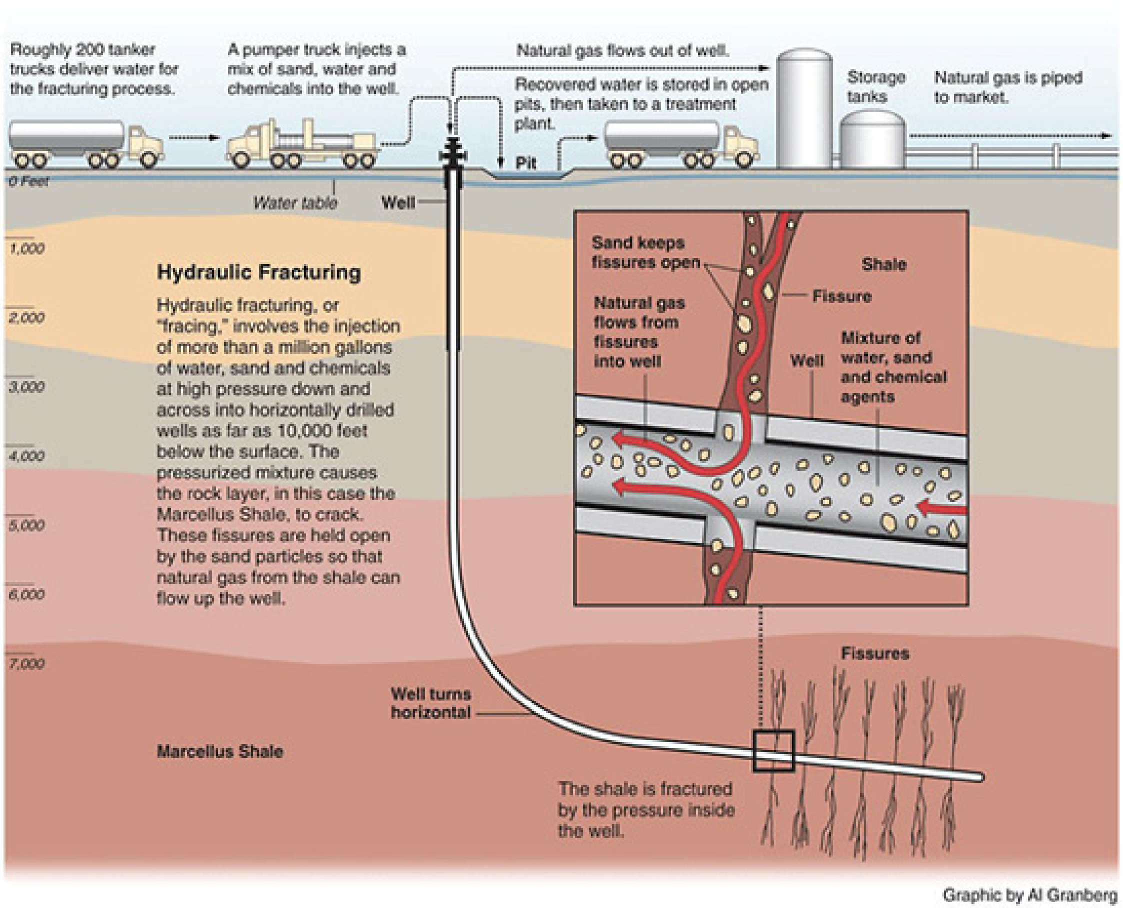
Table 3 – Estimated Shale Gas Reserves in Five US Fields, Tcm

	Produced/Proved Reserves	Undeveloped Recoverable Resource	Resource Endowment
Barnett	0.5	1.1	7.1
Fayetteville	0.1	1.4	9.1
Woodford	0.1	0.8	8.5
Haynesville	0	3.7	22.4
Marcellus	0	6.2	49.9
Total	0.7	13.3	96.9

Source: V. Kuuskraa, Advanced Resources International, Inc. (ARI), Arlington, VA, "Gas Shales Drive the Unconventional Gas Revolution," NCAA-USAEE-CSIS Conference, March 9, 2010, Washington, D.C.

Shale seams consist broadly of horizontal layers 2,000 to 4,000 meters beneath the ground surface, thus drilling likewise is horizontal in direction, once vertical drilling has established the correct seam depths (see illustration in Figure 7).

Figure 7 – Illustration of Horizontal Drilling and Hydraulic Fracturing (EIA)



Principal extraction technologies for unconventional gas resources consist of hydraulic fracturing ("hydro-fracking" or simply "fracking"), i.e., injecting at high pressure and volume a mix of largely water and mud into wells drilled from a ground level pad into tight, shale or coal seams. The water stream is necessary to force the mud particles into the shale seam, effectively creating pores in shale for the methane to move out through the well.

Shale well drilling is considerably more capital intensive than drilling conventional onshore gas wells at comparable depths. Moreover, individual shale wells have notoriously steep decline rates that cause second and third-year gas production to decrease by more than half from the initial level before leveling to rather steady levels for the remaining life of the well. This steep initial decline characteristic results in a need for continuing and intensive drilling activity in order to maintain even constant, let alone rising levels of gas production from a program of shale gas wells. Consequently, low gas prices such as the first-quarter 2012 Henry Hub average of $2.74 per MMBtu[6] for a sustained period of time would threaten to reduce shale gas production significantly.

Despite high drilling costs and steep decline rates, however, prolific gas volumes available in an increasingly diverse array of shale fields have justified the economics in recent years, even at exceptionally low 2009-2012 North American gas prices and production of gas from shale in the US has grown by ten-fold during the past decade. Shale gas is expected to contribute more than 250 Bcm to domestic supplies in 2012, equal to 36% of expected U.S. natural gas production, and by some estimates will reach approximately 345 Bcm in 2020.[7]

On the other hand, a number of recent shale gas technology improvements have reduced per-unit drilling and production costs, enabling shale gas volumes to increase in the US and Canada. Improvements have taken many forms, some quantum and some marginal, some developmental, some programmatic, some environmental, some financial, and some purely operational. Recent production improvements have been enabled by:

- Focusing investments on higher grade, more oil-prone fields, e.g., Eagle Ford and Bakken; higher-grade fields, e.g., Horn River, Marcellus; while de-emphasizing older, more marginal, and more gas-prone fields

- Multi-well pads. Combining drilling operations to a smaller number of pads, thus reducing per-unit costs of surface operations, e.g., somewhat analogous to multi-well offshore production platforms.

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6 Average of January through March 2012 NYMEX gas futures contract settlements.

7 Vello A. Kuuskraa, Advanced Resources International, Inc., Arlington, Virginia, USA, "Gas Shales Drive the Unconventional Gas Revolution," March 9, 2010, Washington Energy Policy Conference on the Unconventional Gas Revolution, National Capital Area Chapter/US Association for Energy Economics, Center for Strategic and International Studies, Washington, D.C.

- Recycling of return water from hydraulic fracturing, thus capturing valuable liquids, reducing water demand, and preventing the most serious pathway to the groundwater
- Use of longer, multi-stage horizontal well bores, and more intensive stimulation techniques
- Making use of skid-mounted, mobile rigs, thus reducing set-up time and costs
- Reducing the composition of gels, chemicals and other costly materials in fracking waters, thus also mitigating water quality concerns
- Scheduling and carrying out drilling operations in shorter time periods, by some reports less than half the number of months from original schedules.[8]

The foregoing technologies and measures, as well as others, have greatly increased shale well productivity and have reduced program break-even costs.

In addition, shale gas producers in North America widely take advantage of rising gas futures prices by hedging, thus ensuring more favorable returns that would be possible under current gas prices. To do so, producers simply sell forward portions of their future gas production in liquid markets as NYMEX or ICE at locked-in prices for the next 18-24 months using financial instruments tailored to resemble their regions as closely as possible. For example, a producer in the Marcellus would lock in an acceptable price at the nearby Dominion Hub using NYMEX Henry Hub futures in combination with a Dominion Appalachian basis swap. In this way, the producer ensures the basic price at Henry Hub plus (or minus) a fixed differential to the specific regional market into which his gas will be sold.

It is important to recognize that there are a number of issues surrounding shale gas development in North America that may constrain exploration and development activities in several areas. In particular, water issues have presented in two overall respects:

- ***Groundwater contamination.*** In most basins, gas-bearing shale seams are located far beneath groundwater basins, e.g., shale seams are at top depths ranging from 2,000-4,000 meters; groundwater basins are typically at bottom depths of no more than 700-800 meters. Non-porous bedrock separates the two layers, as depicted in Figure 7, thus preventing material from one layer from mixing into the other. Sealed

[8] List of technologies adapted from Kuuskraa, op.cit., and Jen Snyder, Wood McKenzie, Cambridge, Massachusetts, USA, "Cost Declines—Fueling the Shale Explosion," March 9, 2010, Washington Energy Policy Conference (see note above).

drill-pipes routinely traverse aquifers to avoid direct contact with groundwater, although occasional instances of groundwater contamination caused by ruptured drill-pipe have been reported. Moreover, naturally occurring fractures or fissures in the bedrock may inadvertently provide transport channels among strata. In relatively rare instances where transport through the bedrock has been available, fracking pressures were suspected of driving native hydrocarbons from shale seams up into groundwater aquifers. Reports of benzene and other drinking water contamination near shale gas fracking operations have prompted environmental regulators to restrict shale-drilling operations in some locations until a better understanding of the processes at work could be gained. In one celebrated case, New York City's water supply, which is derived from aquifers beneath five counties in the eastern fringe of the Marcellus Basin and transported through tunnels in the bedrock, was deemed sufficiently threatened to necessitate suspension of shale gas drilling operations in all five counties. The US Environmental Protection Agency (EPA) has commenced an in-depth analysis of the foregoing issues with the goal of determining if the agency needs to regulate shale gas drilling operations under the US Safe Water Drinking Act. In another case, Wyoming drillers were fracking into shale seams located quite near aquifers, with the predictable result that groundwater became contaminated with fracking water and return water. The EPA's report termed the incident exceptional.

- ***Wastewater disposal.*** Fracking fluids consist largely of water and sand (as a propping agent), although some drillers also use a variety of other substances, including 1-2 percent concentrations of biocides, gels, and organic substances to improve performance.[9] Some of the fluids injected into shale seams in fracking operations reemerge in return water from wells under fairly high pressures ("flow-back"). Flow-back consists of much the same materials that went into the well, plus various other solids, hydrocarbons, and other materials resident within the shale seam. If not fully recycled, flow-back is effectively an industrial effluent that must be treated and disposed of properly. Before the price of liquids increased to exceptionally high values in 2011-2012, flow-back was handled in several different ways: some was spread on land away from aquifers to prevent leaching into groundwater, some was disposed of in adjacent waterways, and some was trucked off-site to public wastewater treatment plants for disposal to the extent of available capacity. The sheer volumes of fracking wastewaters, together with reported instances of impermissible wastewater disposal practices, excessive truck traffic, and the like, prompted regulators to examine shale gas operations more closely to ensure compliance with the US Clean Water Act and other state and local laws. More recently, producers have begun to fully recycle flow-back waters in order to maximize recovery of benzene and other valuable liquids – those that do so effectively eliminate this pathway to the groundwater.

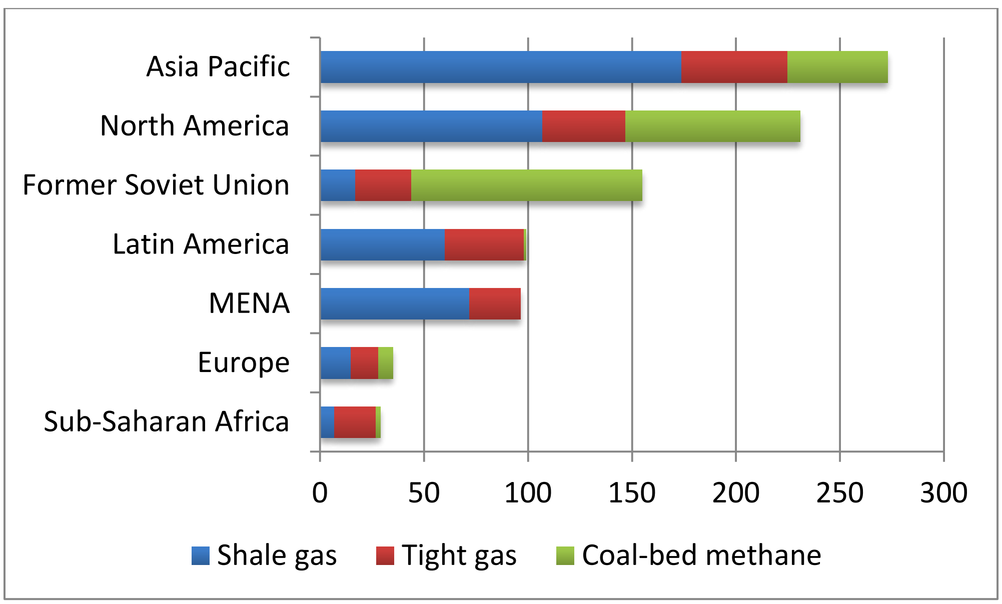
[9] 134 shale producers voluntarily report fracking water components, which typically include acid friction reducers, surfactants, gelling agents, scale inhibitors, ph adjusting agents, breakers and crosslinker, and iron control corrosion inhibitors.

Conclusion. Shale gas in North America has almost suddenly created a continental gas supply surplus that is likely to last for decades. Reserve (p50) estimates place the US just behind the Russian Federation among future gas suppliers. High and rising US shale gas drilling and production levels despite rather low prices appear to violate the laws of gravity, but are motivated by improved technology and high liquid prices (which also are an incentive to recycle flow-back waters). Thus far, two LNG export projects have been unconditionally approved based on liquefying North American shale gas – Kitimat in British Columbia and Sabine Pass in Texas – and six others have been approved but restricted to countries with which the US honors Free Trade Agreements (FTA). Water and other environmental issues appear to be resolving. Exceptionally low gas prices in North America, however, are expected to prevent further quantum production increases of the kind experienced in 2008-2012 until the economics improve.[10]

2.1.5. Shale and other unconventional gas potential beyond North America

Apart from the US and Canada, major unconventional gas deposits have been estimated by the IEA (see Figure 8) and, just for shale gas, by the US Energy Information Administration (see Figure 9). For example, there are proved CBM reserves as well as vast shale gas potential in China, India, Europe, South Africa, India, and other regions. LNG liquefaction projects in Queensland and North America will be supplied from unconventional gas. Acreage allocation and test-well activity has begun in Algeria, Argentina, France, Germany, Hungary, Oman, Pakistan, Poland and Romania.

Figure 8 – IEA Estimate of Unconventional Natural Gas Resources, Tcm



Source: IEA 2011.

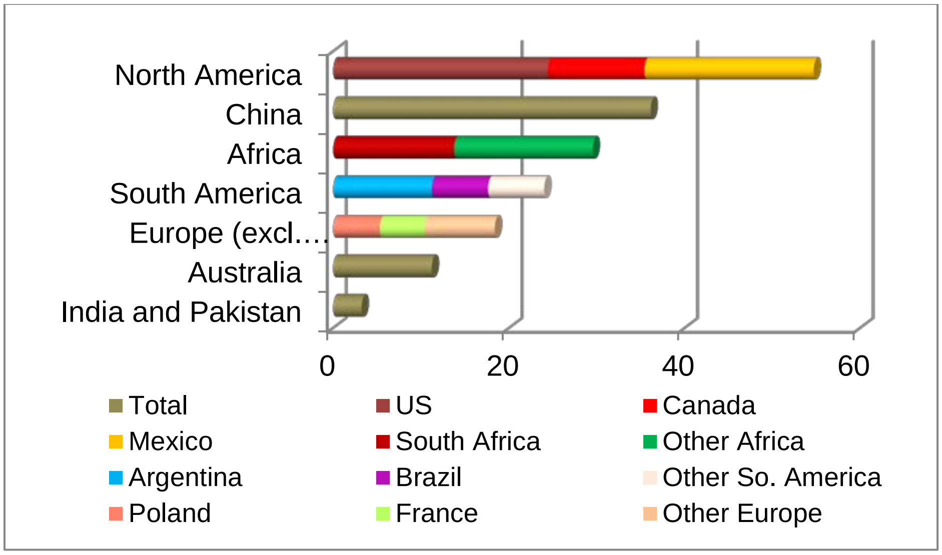
[10] Further discussion of LNG export terminals in presented in subsequent sections of this chapter.

Table 4 – Risked Gas In-Place and Technically Recoverable Shale Gas Resources: 32 Countries, Tcm

Continent	*Country*	*Risked In-Place (Tcm)*	*Technically Recoverable Resource (Tcm)*
North America	USA		
	Canada	42.2	11.0
	Mexico	67.0	19.3
Subtotal, North America		***109.2***	***30.3***
South America	Columbia	2.2	0.5
	Venezuela	1.2	0.3
	Argentina	77.4	21.9
	Bolivia	5.4	1.4
	Brazil	25.7	6.4
	Chile	8.1	1.8
	Paraguay	7.1	1.8
	Uruguay	2.4	0.6
Subtotal, South America		***129.4***	***34.7***
Europe, Eastern	Poland	22.4	5.3
	Lithuania	0.5	0.1
	Kaliningrad	2.2	0.5
	Ukraine	5.6	1.2
Subtotal, Eastern Europe		***30.7***	***7.1***
Europe, Western	France	20.4	5.1
	Germany	0.9	0.2
	Netherlands	1.9	0.5
	Sweden	4.6	1.2
	Norway	9.4	2.4
	Denmark	2.6	0.7
	UK	2.7	0.6
Subtotal, Western Europe		***42.6***	***10.5***
Africa	Algeria	23.0	6.5
	Libya	32.5	8.2
	Tunisia	1.7	0.5
	Morroco	3.1	0.5
	South Africa	52.0	13.7
Subtotal, Africa		***112.2***	***29.5***
Asia	China	144.5	36.1
	India	8.2	1.8
	Pakistan	5.8	1.4
	Turkey	1.8	0.4
Subtotal, Asia		***160***	***40***
Australia		***39***	***11***
TOTAL, ALL		**624**	**163**

ARI, World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the US, for EIA, 4/11.Table 1-3.

Figure 9 – US EIA Estimate of Shale Gas Resources, Tcm



Source: BSA 2011 graphic, from ARI/EIA, see Table 4*.*

Within Europe, the U.S. EIA's findings shown in Figure 9 (and corresponding data in Table 4) suggest a highly positive outlook for shale gas, particularly in Poland, with an estimated 5.3 Tcm of technically recoverable resources. One must keep in mind the limitations of EIA's assessment, however, as it is based on geological similarities between shale plays in the U.S. and formations in other countries for which log data are available. Consequently, Eastern Europe's shale gas prospects are hypothetical at this point, and must await the results of exploratory drilling and analysis.

European shale gas prospects are centered in three macro basins:[11]

- Poland and Scandinavian countries – Alum Basin (Denmark and Sweden), Norwegian-Danish Basin, Silurian Shale (Poland), Gdansk Depression (part of the Baltic Basin running east to northwestern Russian Federation). Fifteen drilling concessions thus far, largely in Poland, including ConocoPhillips, ExxonMobil and others.

- England and Northern Europe – northwestern England (Cheshire Basin) following Anglo-Dutch Basin through the southwestern North Sea into the Netherlands and northwestern Germany, and Posidonia shales of northeastern Poland.

- Western Europe – southern England (Weald Basin) through Paris Basin, northwestern Germany, Switzerland (Mulasse Basin).

[11] Adapted from Ken Chew, Ph.D., IHS Inc., "The Shale Frenzy Comes to Europe," March 1, 2010, Hart's E&P.

Thus far (at year-end 2011), Poland is the most advanced in this respect, with more than 100 wells, while other countries are far behind; media reports indicate that only about a dozen shale wells have been drilled in promising shale fields in Hungary and Ukraine.

Table 5 provides a country-by-country listing of potential gas-bearing shale basins in Europe but shale well drilling in other European countries has yet to commence to any appreciable degree.

Table 5 – Potentially Significant Shale Gas Plays in Europe, by Country

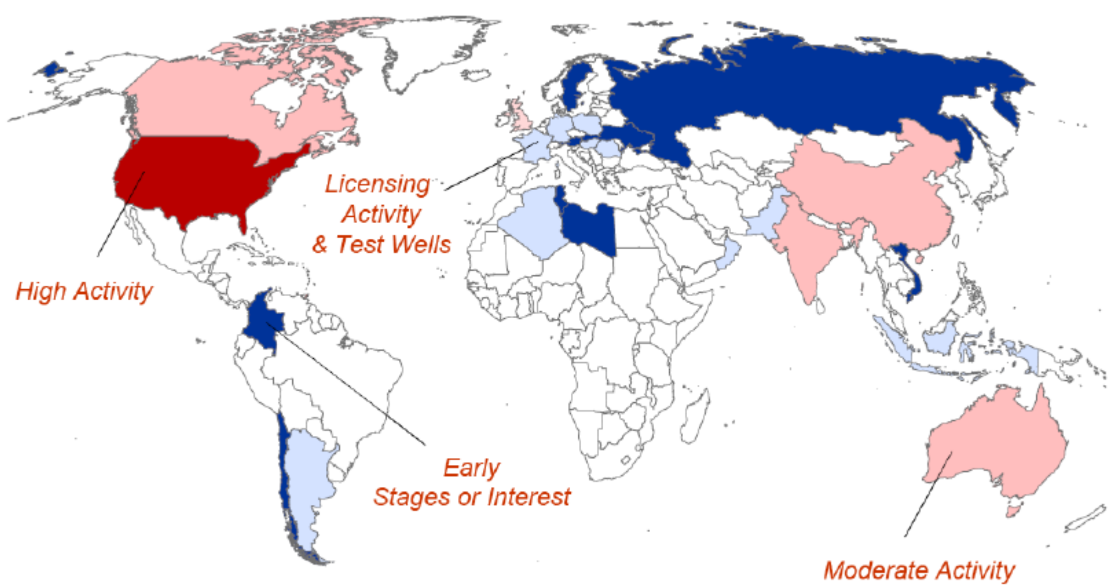
Country	*Basin*	*Top Depth, Thickness (m)*
Austria	Vienna Basin	4,900
Denmark	Norwegian-Danish (Alum Basin)	NA, 160 m thickness
France	Paris Basin	
Germany	Northwest German Wealden Basin and Posidonia Shales	NA, 35 m thickness
Netherlands	Central Graben	3,500, 170 m thickness
	West Netherlands (Anglo-Dutch	3,000-4,200, 450 m thickness
	Anglo-Dutch	3,800, 30 m thickness
Poland	Baltic Depression	2,100-3,800, 150-750 m thickness
	Danish-Polish Marginal Trough	4,000
	Fore-Sudenic Monocline	900-4,000, 30-300 m thickness
Sweden	Fennoscannian Border Zone (Alum Basin)	100 m thickness
Switzerland	Molasse Basin	
United Kingdom	Cheshire	1,300, 1,200 m thickness
	Weald	600 m thickness

Source: Benjamin Schlesinger and Associates, LLC, adapted from K. Chew, Ph.D., IHS Inc., "The Shale Frenzy Comes to Europe," March 1, 2010, Hart's E&P.

Results of European shale gas drilling operations thus far appear mixed. Halliburton conducted initial hydraulic fracturing operations for the Polish Oil and Gas Company (PGNiG) at the Markowola-1 well in August 2010; discouraging results suggested that the fracturing technology needed to be adapted to geological conditions more specific to Poland. Also in 2010, ExxonMobil withdrew from Hungary, which had been considered promising, after failing to discover commercial quantities of shale gas. On the other hand, three local producers – PGNiG in Poland, RAG Rohol-Aufschungs in Hungary, and Kulczyk Oil Ventures in Ukraine – have each claimed field successes. While commercial production has yet to evolve, exploratory programs are continuing in light of the region's considerable potential.[12]

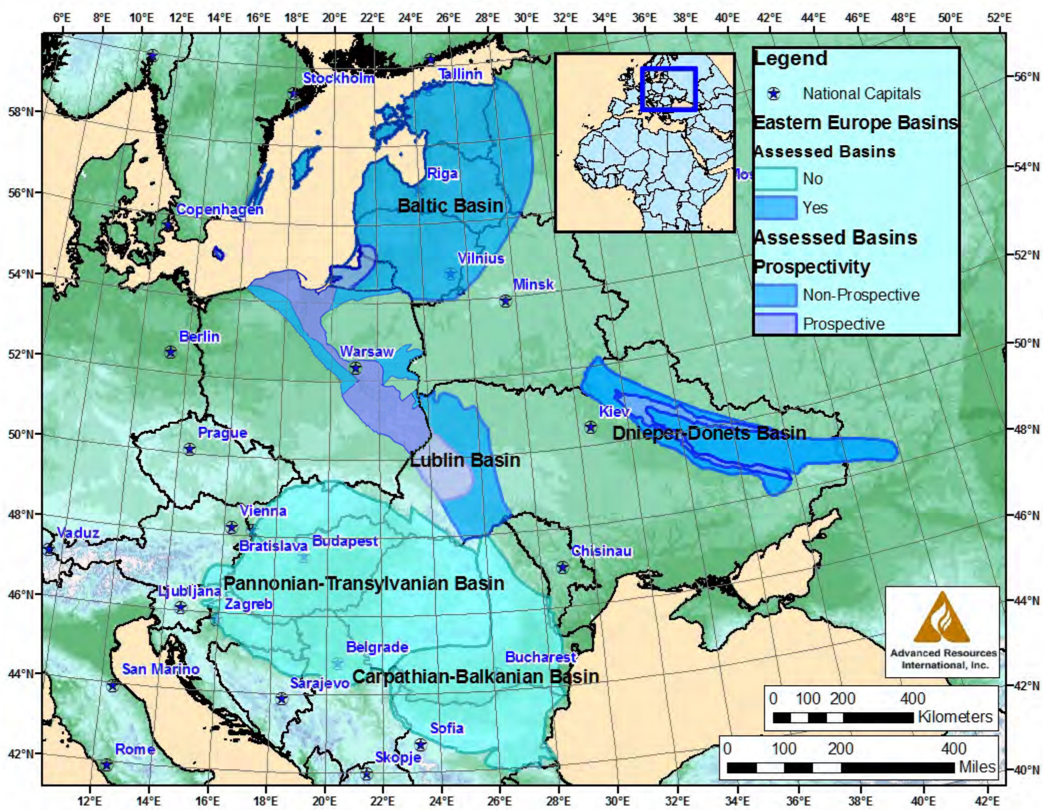
It is important to recognize that "shale gas exploration in Europe is in its infancy," as Dr. Chew of HIS put it (Harts E&P, March 1, 2010). Production levels have barely begun, and may not be realized in a statistically noticeable way for several years. For example, it took five years for shale gas production in the US's first major new field (Barnett Shale) to increase from 1 Bcm p.a. in 1999 to 10 Bcm p.a. in 2004, before peaking in 2008 at about 35 Bcm p.a. In addition, Europe will likely face some of the same kinds of water and other environmental issues that have emerged for shale gas in North America. Further, an array of legal issues related to land use and royalties may need to resolve differently in Europe from North America, e.g., the Crown or state retains mineral resources rights beneath privately owned lands throughout most of Europe and China, thus preventing surface residents from receiving royalties in a direct way, as in the U.S., although economic rents may otherwise be captured under arrangements granting permission to access and cross private lands.

Figure 10 – Map of Unconventional Gas Development Activity



[12] For further discussion, see V. Ivanenko and B. Schlesinger, Political Economy of Shale Gas Industry in Eastern Europe, IAEE Energy Forum, January 2012.

Figure 11 – Location of Shale Gas Resources in Eastern Europe



Source: Advanced Resources International, Inc., 2011. World Shale Gas Resources: An Initial Assessment of 14 Regions outside the United States, April 2011.

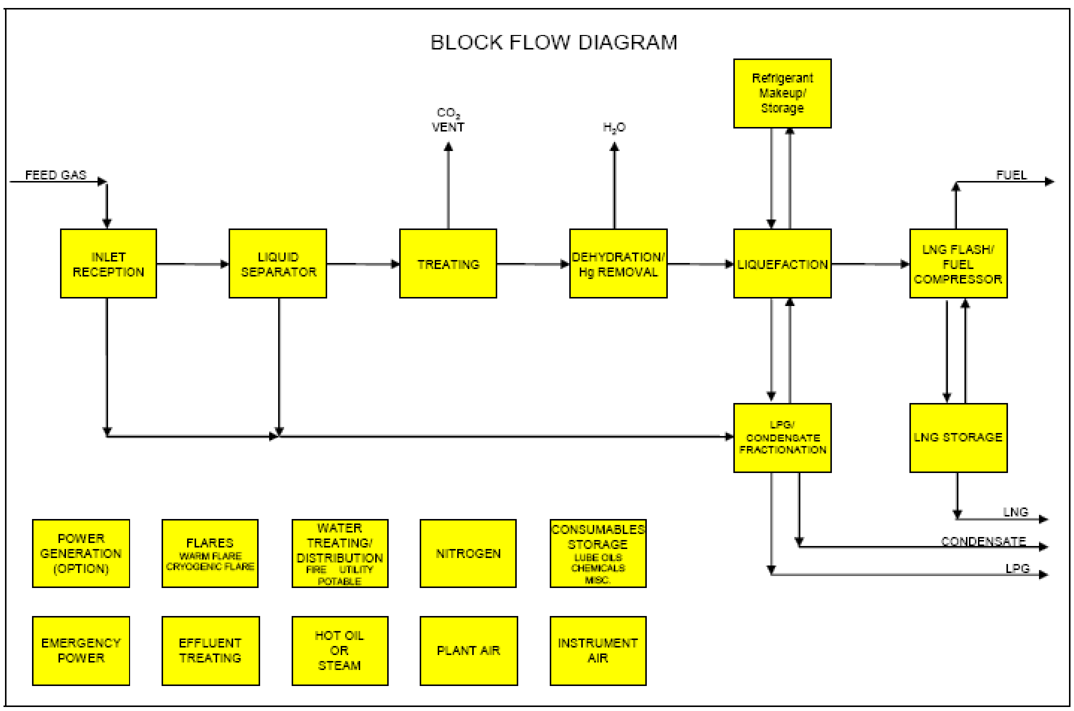
Conclusion. A number of countries in Central and Western Europe are believed to hold shale gas deposits that collectively may be on a scale comparable to those in North America. China claims to hold up to 50 Tcm of shale gas deposits as well. Upon exploration, the same may eventually hold true in the Russian Federation, India and other countries that were not included in the EIA's global review (thus not included in Figure 9 and in Table 4).

Finally to this section, for purposes relating to asset acquisition, taxation and royalty matters, accounting for proved gas reserves (i.e., p90 or p100 gas) is both relevant and necessary. In contrast, however, for purposes of forecasting gas producing and transportation patterns in the future beyond the 12-24 month time frame, accounting for p50 gas reserves is necessary. Employing this larger volume of gas is crucial to understanding potential supplies based on prodigious North American shale gas resources, as well as European, Chinese and other potential unconventional gas resources.

2.2. Liquefaction

Liquefaction is the most capital and energy intensive component of the LNG value chain. It consists of processes that chill natural gas to the point where it becomes converted to a liquid, i.e., at an average temperature of minus 161 ºC (minus 258 ºF). In order to achieve this low temperature, the gas transfers heat to a refrigerant fluid that has been previously chilled in a cooling cycle so that, in effect, this fluid steals the heat from natural gas until it is liquid. This is a process with an intensive consumption of energy (275-400 kWh/ton GNL).

Figure 12 – Block Flow Diagram of an LNG Liquefaction Plant

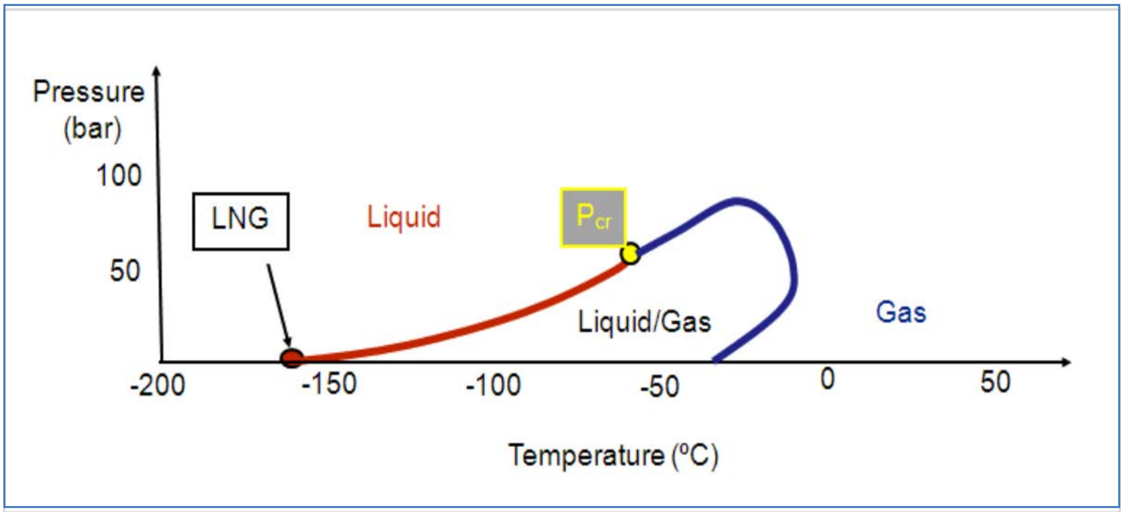


Prior to the liquefaction process, the feed gas, which flows directly from the reservoir to the liquefaction facility by pipeline, receive such treatments as:

- Filtration and solid removal
- Liquids separation
- Removal of acid gases dissolved in the water and carried in the natural gas stream as CO_2 or H_2S
- Dehydration
- Mercury removal

It is important to note in the liquefaction process that, as Figure 13 illustrates, natural gas must be fully chilled to minus 161^{o} C so that it is completely liquefied. Otherwise the gas will exist partly in each phase, liquid and gas, and thus cannot be transported either as LNG or in pipelines using today's technologies.

Figure 13 – Natural gas phase diagram



High efficiency cooling is necessary to liquefy the natural gas by condensation. This is typically achieved by either of two different methods:

- Forcing the gas to develop a reverse thermodynamic cycle, i.e. expanding it after being compressed and cooled (in one or several steps)

- Allowing a heat exchange between the gas and a cooler fluid known as refrigerant or coolant, which has previously been chilled by a reverse thermodynamic cycle.

These two liquefaction methods are applied in different technologies that can be classified according to the refrigerant nature or thermodynamic cycle.

2.2.1. Description of current applicable technologies for liquefaction

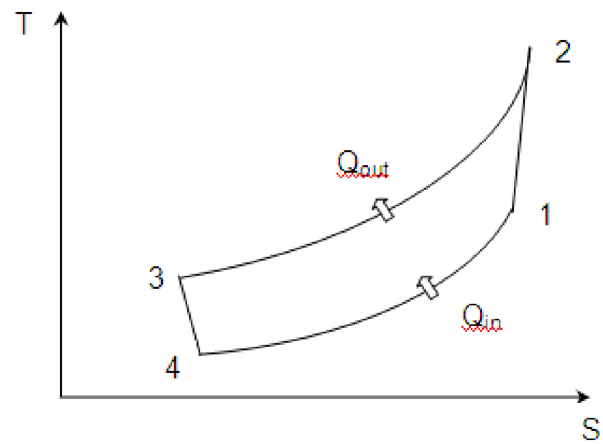
The applicable technologies for LNG liquefactions considered in this report may be divided into three main groups; each of these technologies is discussed as follows:

1. Technologies based on expansion refrigeration cycles
2. Technologies based on mixed refrigerant cycles (with or without pre-cooling)
3. Technologies based on multiple refrigeration cycles

2.2.1.1. *Technologies Based on Expansion Refrigerant Cycles*

This technology does not entail changing the phase of the refrigerant fluid, i.e., the coolant remains as a gas through the process. The refrigerant is a gas that follows a reverse Brayton cycle. Steps in this cycle are a) compression-cooling at high temperature, and b) expansion-heating at low temperature. No phase change takes place, so the refrigerant fluid is gaseous throughout the cycle. Refrigerant heating is used to cool down and condense the natural gas. A single main cryogenic heat exchanger (MCHE) is used for this central step of the process.

Figure 14 – Inverse Brayton Cycle, T-S Diagram



Technology based on expansion refrigerant cycles is widely used on peak-shaving installations. Peak-shaving plants offer a very low production rate (0.1 – 0.2 mtpa), although some technologist are promoting the development of higher production rates.

The essentials of this process are: simple start up/operation/shut down, use of non-flammable refrigerants in most facilities, direct generation of refrigerant, modularity, compactness and lightness compared to equivalent size plants.

This type of process is especially suitable for offshore installations for safety reasons as there is no need to place hydrocarbons reservoirs on board. However, the safety restrictions that apply offshore are not so relevant when the installation is placed onshore to the extent safe facility distances can be maintained.

Finally, another major positive factor is the simplicity of the process, which allows quick and simply start-up procedures, thus reducing the amount of gas vented or flared.

On the other hand, the major handicaps of this technology, against mixed refrigerant processes are: a) lower efficiency, b) higher requirements for refrigerant fluid, and c) higher number of rotary systems. In order to improve the low efficiency of the process, expansive engines are used instead of Joule-Thompson valves. The use of expansive engines enables recovery of some of the dynamic energy involved in the process, which is usually applied by a shaft on the compression stage.

With rising interest in offshore liquefaction, significant interest has evolved in developing and refining this particular type of technology. Latest improvements have increased the production capacity of the newest facilities to 1 mtpa.

Technologies based on expansion cycles could be classified as:

- Technologies based on the expansion of nitrogen
- Technologies based on the expansion of natural gas (feedgas or boil-off gas)
- Gas expansion technology combined with other processes.

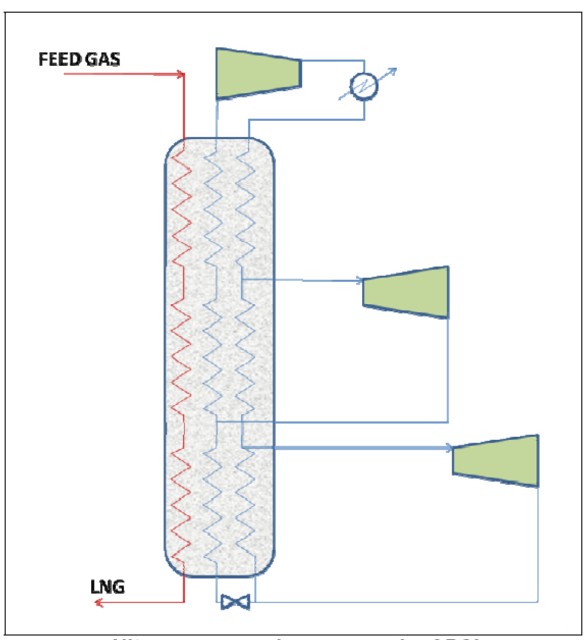
Current research on this technology is focused on improving liquefaction efficiencies as well as overall the efficiency of the facility itself, reducing the amount of industrial equipment, and allowing the pre-manufacture of independent modules.

2.2.1.1.1 Technologies Based on the Expansion of Nitrogen

The nitrogen refrigeration cycle is commercially owned by a number of firms, both as a single cycle or as a combination of many cycles. In this process, nitrogen is used as a gas reproducing an inverse Brayton cycle.

In the process diagrams shown below, the nitrogen works at different pressure rates. Several expansive engines recover part of the compression energy transferring it back to the compressors.

Figure 15 – Nitrogen Expansion Process (APCI)

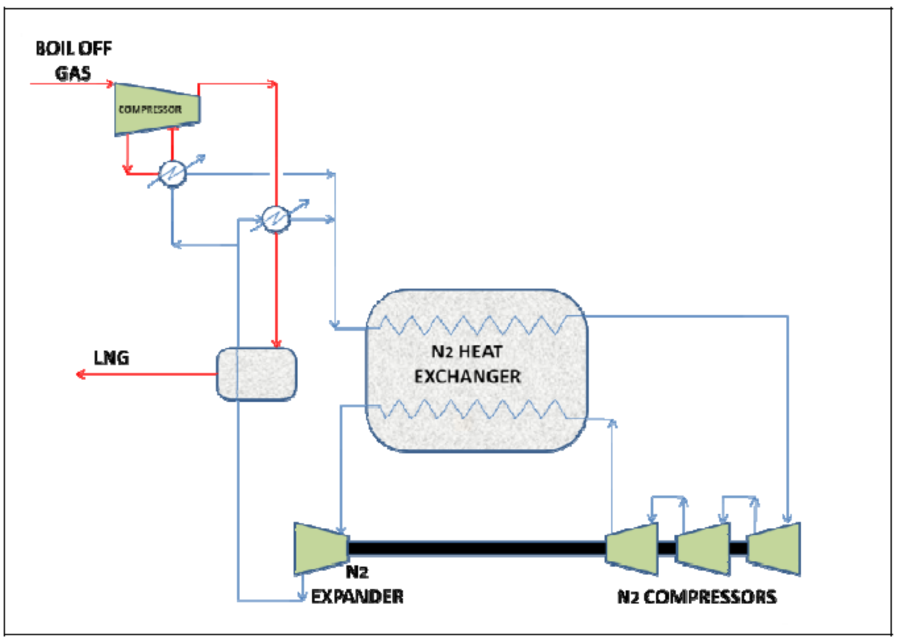


Nitrogen expansion process by APCI

There are different processes based on this technology and offered by different process licensors: APCI (Air Products and Chemicals, Inc.), Mustang, BHP, Hamworthy, etc.

The heat exchange from the natural gas to different coolant streams takes place in a main heat exchanger. The aim of the operation is to maximize the efficiency of the process. This is achieved performing a heating curve for the refrigerant as close and parallel as possible to the gas natural heating curve. The main heat exchanger is usually formed by series of tubes or by aluminium plate-brazed. As it has been mentioned above, this processes use not-flammable refrigerant becoming very attractive for floating installations. In fact, this technology has been chosen to be installed at the Q-Max and Q-Flex LNG carriers to reliquefy boil-off gas. The diagrams of those installations can be observed in Figure 16.

Figure 16 – EcoRel Process (Cryostar)



EcoRel process by CRYOSTAR

2.2.1.1.2 Technologies Based on the Expansion of Natural Gas

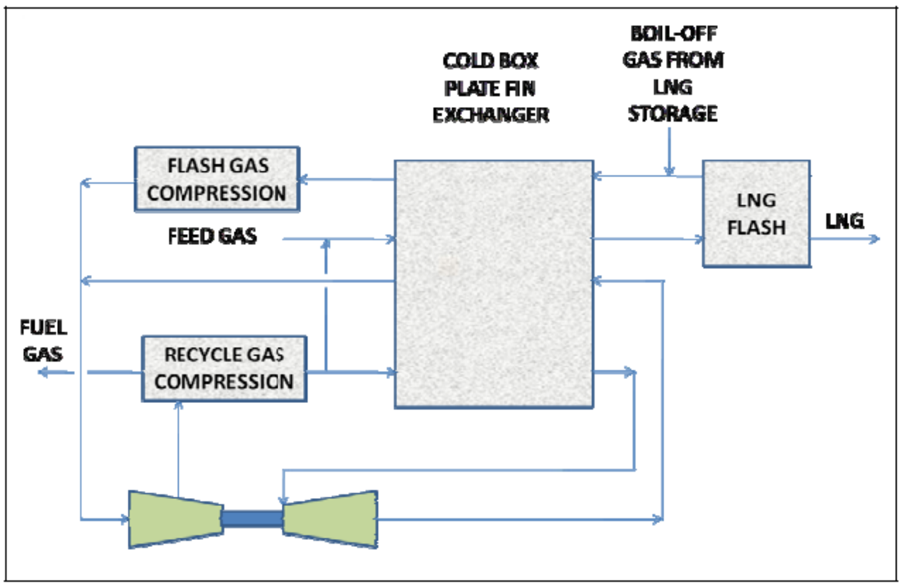
This type of process replaces the nitrogen cycle by an inverse cryogenic Brayton cycle applied to the natural gas so there is no need for a separate refrigerant fluid. The diagram in Figure 177 shows a typical arrangement.

A single or many expansive engines are used in order to recover part of the energy contented in the pressurized gas. The design of the expansive engines is the main difference among the different process based on this technology.

In order to improve the efficiency of the liquefaction process and to reduce the consumption of fuel gas, the expansion process is complemented by another simple cooling cycle. The extra cycle added to the expansion process can be either a pre-cooling stage using propane or ammonia (i.e. an inverse Rankine cycle) or a double gas cycle of methane and nitrogen that reduces the amount of refrigerant stored.

The exchange of heat is carried out in a single cryogenic heat exchanger unit that allows the flow of different streams through various independent channels.

Figure 17 – OCX-2 Natural Gas Expansion Cycle (Mustang)



OCX-2 process by Mustang

2.2.1.2. Technologies Based on Mixed Refrigerants

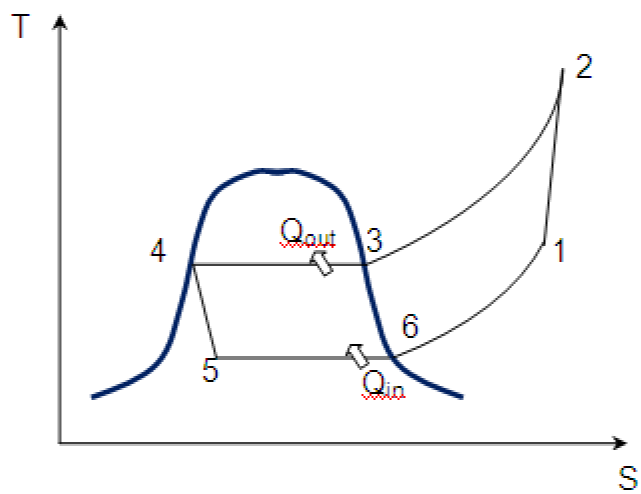
2.2.1.2.1. Without precooling stage

Mixed refrigerant suffers a double phase change: liquid to gas (evaporation) and gas to liquid (condensation). This single mixed refrigerant process (SMR) is basically an inverse Rankine cycle where the gas is chilled and liquefied in a single heat exchanger (MCHE).

The refrigerant is a mixture of several compounds (mainly hydrocarbons and nitrogen) and follows a reverse Rankine cycle with the following stages: compression-cooling-condensation (at a high temperature); expansion-evaporation (at a low temperature).

There are different technologies of SMR available in the market with references of this process since the 1970´s: Among all the mixed refrigerant processes, the SMR provides simpler configurations of the facilities, allowing a lower CAPEX, smaller footprint (less site area requirement), easier start up, and lower maintenance costs. However, the operation of the facilities based on this technology demand a higher cost in terms of energy consumption.

Figure 18 – Inverse Rankine Cycle, T-S Diagram



The composition of the mixed refrigerant depends on the specific requirements of the site and is mainly formed by natural gas liquids (methane, ethane, propane, butane, pentane) and nitrogen mixed in different proportions to optimize the energy consumption of the process. The efficiency of the process is optimal when the curve of the evaporation of the refrigerant is identical to the cooling and liquefaction curve of the natural gas.

There are several available technologies, such as:

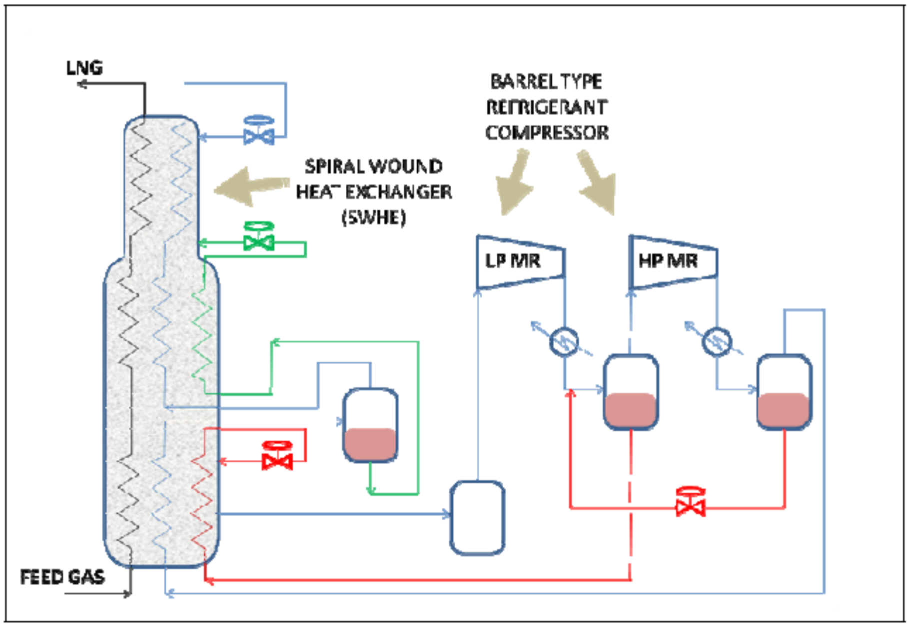
- PRICO Process (Poly Refrigerant Integrated Cycle Operation) by Black and Veatch
- TEAL Process (Technip-Air Liquide) used in Skikda 1 (Algeria)
- SMR Process by APCI (called AP-M)
- LiMuM Process (Linde Multi-Stage Mixed Refrigerant)
- Kryopak SCMR Process.

The diagram in Figure 19 illustrates the Linde Multi-State Mixed Refrigerant process, which operates with a mixed refrigerant cooling cycle:

The process comprises different principal elements such as the refrigerant compressors (usually two of them but in some cases a single one) and a main cryogenic heat exchanger where the natural gas is chilled and condensed. This heat exchanger is usually a multi-tubular winding within a shell or series of aluminium braze-plates.

The mixed refrigerant usually operates at different pressure ratios in order to reduce the amount of gas required as the efficiency is also improved. Once in operation, the facilities that operate by this process have the possibility of withdrawing heavier hydrocarbons from the natural gas stream. These heavier compounds can be used as components of the mixed refrigerant fluid, becoming the facility in an independent site regarding the refrigerant fluids.

Figure 19 – LiMuM Process (Linde)



LiMuM process by Linde

2.2.1.2.2 With Pre-cooling Cycle

During the last 30 years, the most popular technology among the liquefaction plants is the pre-cooling cycle combined with mixed refrigerants.

Specifically, the C3-MR Process licensed by APCI has been chosen by most of the liquefaction plants with a capacity below 5 mtpa.

This technology adds a pre-cooling stage to the mixed refrigerant reverse Rankine cycle, reducing the energy consumption of the overall process (by increasing the efficiency). This extra cycle is used to pre-cool the natural gas and/or to cool and condensate the refrigerant. This precooling stage is usually generated in a reverse Rankine cycle or in an absorption cycle. The downside of this modification is the higher complexity of the resulting installation.

The pre-cooling stage is used for two different applications:

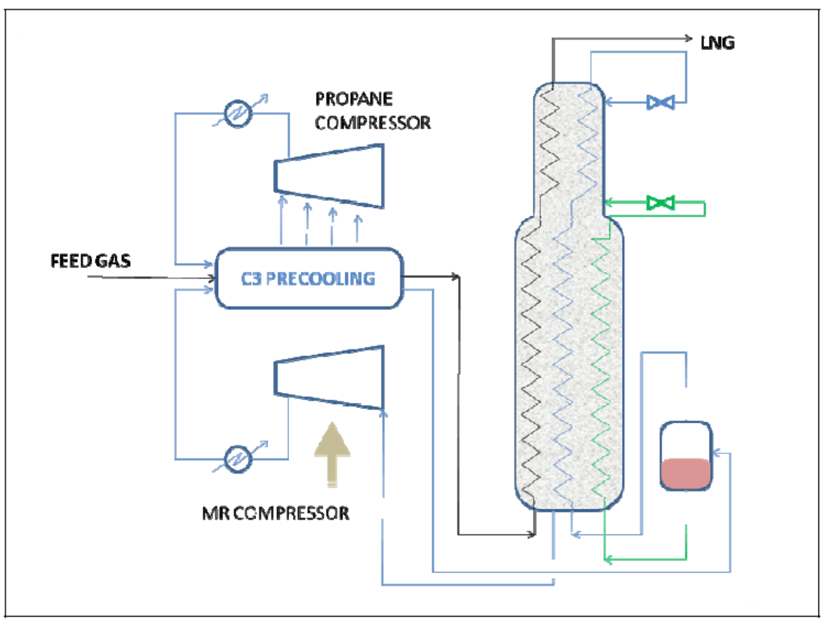
- To cool down the feed gas that will be liquefied
- To condensate the mixed refrigerant used in the main refrigeration cycle

There are different options to this additional cycle:

- Refrigeration with propane following an inverse Rankine cycle
- Refrigeration with ammonia following an inverse Rankine cycle
- Refrigeration with ammonia following an absorption cycle (taking advantage of the residual heat produced by the turbine's output that acts on the main compressors). This technology can also use a main cryogenic heat exchanger (wound tubes inside a shell or aluminium brazed-fin).

The following figure shows different solutions proposed by different liquefaction process licensor of mixed refrigerant with pre-cooling cycle:

Figure 20 – C3-MR process (APCI)



C3-MR process by APCI

2.2.1.3. Technologies based on multiple refrigeration cycles

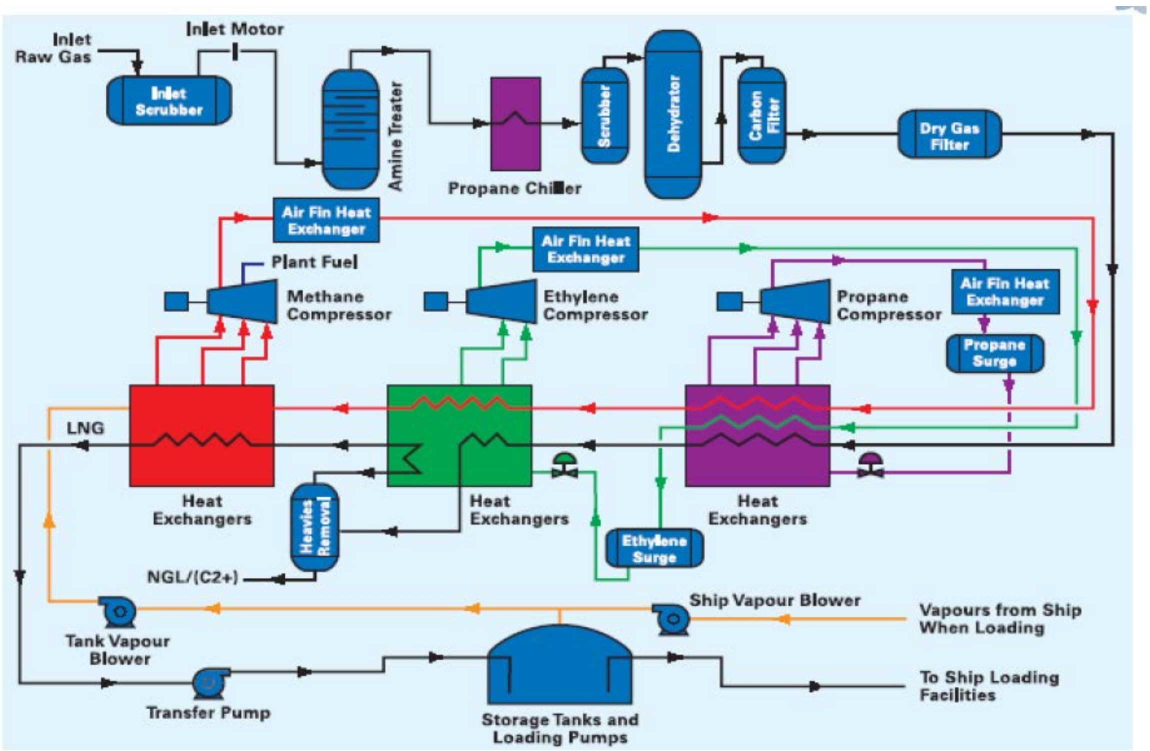
Liquefaction processes described in previous sections have only a single refrigeration cycle (and a pre-cooling stage in some cases). More complex technologies employ a cascade of multiple refrigeration cycles.

Refrigeration is provided in each stage by an inverse Rankine or Brayton cycle with different pure or mixed refrigerants.

There are several technologies available:

- Conoco Phillips Optimised Cascade. This design has three consecutive refrigeration cycles: propane pre-cooling, ethylene liquefaction and methane sub-cooling, as shown in Figure 21. A significant advantage of the ConocoPhillips multi-stage process is the opportunity for modular construction. This process has been installed in Kenai LNG (Alaska), in the four trains in Atlantic LNG (Trinidad Tobago), in two trains in Idku LNG (Egypt) and more recently in Darwin LNG in Australia.

Figure 21 – ConocoPhillips Optimised Cascade



- Shell DMR Process. This process consists of two series refrigeration cycles with different options for the dual mixed refrigerants (DMR). This technology was chosen for the Sakhalin LNG plant in the Russian Federation.
- Statoil/Linde MFC Process. This technology is a variant of the cascade process in which the refrigerants are mixed instead of pure. The composition of the refrigerant is a combination of nitrogen, methane, ethane and propane adapted for each stage. The first liquefaction plant setting up this process has been the Snohvit LNG project in Norway.
- APCI AP-X Process. This process consists of a modification of the APCI C3-MR process to improve its efficiency by adding a sub-cooling cycle with a nitrogen expander. This model has three cycles: propane pre-cooling, mixed refrigerant liquefaction and nitrogen expander sub-cooling.

2.2.1. Summary of Liquefaction Technologies

The foregoing processes are summarizes in Table 6 with respect to: Type of technology, Licensor (company), Process, Capacity, References/comments and Energy consumption.

Table 6 – Summary of Major LNG Liquefaction Processes

Type		Company	Process	Capacity (mtpa)	References & Comments	Energy consumption (kWh/ton GNL)
Expansion refrigerant cycles	Nitrogen Expansion	APCI		<0.7	Peak saving plants, small scale	410
		BHP	cLNG	<1.5	Peak saving plants, small scale	455
		Hamworthy	Mark I, II, III	<0.2	Reliquefaction of boil off	800
		Mustang Eng.	NDX-1	<0.65	Peak saving plants, small scale	410
	Gas Expansion	Kryopak	EXP	<0.1	Peak saving plants, small scale	372
		CB&I-Lummus	Niche LNG	<0.9	Potentially floating LNG	400
		Mustang Eng.	OCX-2 OCX-R	<0.75	Potentially floating LNG	400
Mixed refrigerant cycles		Black & Veatch	PRICO	<1.5	Skikda 2 (Algeria)	310
		Technip	TEAL	<0.85	Skikda 1 (Algeria)	410
		APCI	AP-M	0.5-1.8	Marsa el Brega (Libya)	300
		Linde	LiMuM	<2.5		290
		Kryopak	SCMR	<2		300
		APCI	C3-MR	1.4-4.5	70% of base load plants	280
		LNG Ltd	AA-MR	<1.6		275
Multiple refrigeration cycles		Conoco-Phillips	Optimised Cascade	1-5.2	Atlantic LNG (T&T), Kenai (US), Idku (Egypt), Darwin (Australia)	275
		Statoil Linde	MFC	2-5	Snohvit (Norway)	275
		Shell	DMR	3-8	Sakahlin (Russia)	270
		APCI	AP-X	6-8	Qatargas 2 (Qatar)	270

In large-scale plants the process C3-MR of APCI is the one with most presence (in 70% of the liquefaction plants worldwide) as well as the Optimised Cascade Process Conoco-Phillips process. In small-scale plants are multiple processes employed so that there is no clear trend.

In terms of efficiency and cost savings the energy consumption required for the process, seems to be the one of the main drivers, being the C3-MR of APCI the less energy intensive.

2.2.2. Global liquefaction capacity

Global liquefaction plant in operation presently is approximately 261 mpta (at year-end 2012). Liquefaction capacity operations and expansions are summarized in Table 7 through Table 10 by facility status, basin, region and country.

Table 7 – Nominal Liquefaction Capacity, by Facility Status (mpta)

Status	2010	2011	2012	2013	2014	2015	2020	2025	2030
Existing	258,8	277,2	280,9	279,5	276,9	267,7	273,1	277,1	277,1
Under construction				3,4	11,2	43,2	96,8	95,8	95,8
FEED Completed							10,9	13,7	27,4
In FEED							34,4	65,1	73,1
Pre-FEED							6,2	32,6	32,6
Proposed							17,0	28,8	32,8
Decommissioned	1,5	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7
TOTAL	*260,4*	*277,9*	*281,6*	*283,6*	*288,8*	*311,5*	*439,0*	*513,7*	*539,4*

Source: PFC Energy and author's elaboration

Table 8 – Nominal Liquefaction Capacity, by Basin (mpta)

Basin	2010	2011	2012	2013	2014	2015	2020	2025	2030
Atlantic-Mediterranean	78,5	77,8	77,8	79,9	83,6	86,1	127,0	129,8	143,5
Middle East	83,7	99,5	100,3	100,3	100,3	100,3	108,9	115,9	119,9
Pacific	98,2	100,6	103,5	103,4	104,9	125,1	203,1	268,0	276,0
TOTAL	260,4	277,9	281,6	283,6	288,8	311,5	439,0	*513,7*	*539,4*

Source: PFC Energy and author's elaboration

Table 9 – Nominal Liquefaction Capacity, by Region (mpta)

Region	2010	2011	2012	2013	2014	2015	2020	2025	2030
Asia Pacific	94,3	94,7	97,5	99,0	100,5	120,7	188,1	209,2	217,2
East Africa							7,5	30,0	30,0
Europe	4,3	4,5	4,5	4,5	4,5	4,5	4,5	7,3	21,0
Middle East	83,7	99,5	100,3	100,3	100,3	100,3	108,9	115,9	119,9
North Africa	33,0	32,2	32,2	31,3	32,8	31,6	32,4	32,4	32,4
North America	1,5	1,5	1,5	0,0	0,0	3,4	46,3	67,7	67,7
South America	17,9	20,0	20,0	20,0	20,0	20,2	20,5	20,5	20,5
West Africa	25,6	25,6	25,6	28,6	30,8	30,8	30,8	30,8	30,8
TOTAL	260,4	277,9	281,6	283,6	288,8	311,5	439,0	513,7	539,4

Source: PFC Energy and author's elaboration

Table 10 – Nominal Liquefaction Capacity, by Country (mpta)

Country	2010	2011	2012	2013	2014	2015	2020	2025	2030
Algeria	20,1	19,3	19,3	18,4	19,9	18,7	19,5	19,5	19,5
Angola				3,0	5,2	5,2	5,2	5,2	5,2
Australia	19,9	19,9	22,8	24,2	24,2	40,2	93,1	109,1	117,1
Brunei	7,2	7,2	7,2	7,2	7,2	7,2	7,2	7,2	7,2
Canada							3,0	24,4	24,4
Colombia						0,3	0,5	0,5	0,5
Egypt	12,2	12,2	12,2	12,2	12,2	12,2	12,2	12,2	12,2
Equatorial Guinea	3,7	3,7	3,7	3,7	3,7	3,7	3,7	3,7	3,7
Indonesia	34,1	34,1	34,1	34,1	34,7	32,9	38,0	38,2	38,2
Iraq									4,0
Israel								3,0	3,0
Libya	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7
Malaysia	23,9	23,9	23,9	23,9	23,9	23,9	29,9	29,9	29,9
Mozambique							7,5	20,0	20,0
Nigeria	21,9	21,9	21,9	21,9	21,9	21,9	21,9	21,9	21,9
Norway	4,3	4,5	4,5	4,5	4,5	4,5	4,5	4,5	4,5
Oman	10,8	10,8	10,8	10,8	10,8	10,8	10,8	10,8	10,8
Papua New Guinea					0,9	6,9	10,4	10,4	10,4
Peru	2,4	4,5	4,5	4,5	4,5	4,5	4,5	4,5	4,5
Qatar	61,2	76,2	77,0	77,0	77,0	77,0	85,0	89,0	89,0
Russia		9,6	9,6	9,6	9,6	9,6	9,6	17,2	30,9
Tanzania								10,0	10,0
Trinidad	15,5	15,5	15,5	15,5	15,5	15,5	15,5	15,5	15,5
United Arab Emirates	5,8	5,8	5,8	5,8	5,8	5,8	6,4	6,4	6,4
US	1,5	1,5	0,0	0,0	3,4	43,3	43,3	43,3	43,3
Yemen	5,9	6,7	6,7	6,7	6,7	6,7	6,7	6,7	6,7
TOTAL	260,4	277,9	281,6	283,6	288,8	311,5	439,0	513,7	539,4

Source: PFC Energy and author's elaboration

2.3. Shipping

LNG carriers are built to International Maritime Organization (IMO) and international regulations and their safety standards, and LNG carriers are required to operate at a higher standards of safely than other shipping sectors. LNG tankers of necessity employ highly specialized technologies.

2.3.1. Tanker Technologies

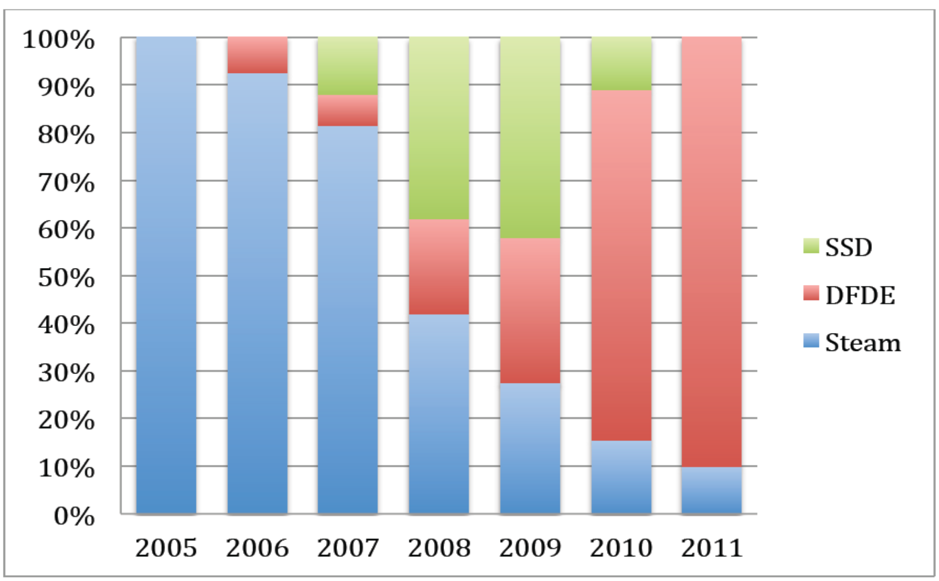
Technological advances have been achieved recently in systems for propulsion, containment, and winterization/ice class improvements.

2.3.1.1. Propulsion Systems

Most recent orders for new vessels have specified reciprocating diesel engines, rather than the traditional heavy fuel oil (HFO) fired steam turbines.

The main advantage of diesel engines is a better efficiency: around 43% against 27% on average for the traditional steam turbines. Other benefits include smaller engine space that offers extra cargo capacity, lower emissions, higher reliability and less complex operation. In addition, manufacturers of diesel engines have produced versions for burning HFO rather than the more expensive marine diesel.

Figure 22 – Photo of QFlex and Standard Vessel



Notes: SSD: slow speed diesel (with re-liquefaction); DFDE: dual-fuel diesel electric. Excludes ships <70,000 m³ and one steam-turbine unit to be delivered in 2012. Four of the DFDE ships are to be delivered with re-liquefaction units.

Two main types of diesel engine have been specified in recent LNG orders: dual-fuel diesel electric (DFDE) and slow speed diesel (SSD). DFDE can also burn boil-off gas, while SSD cannot, thus ships need re-liquefiers. The high price of diesel fuel compared to boil off since 2010 has provided a strong incentive to modify SSD vessels to accept boil-off gas as their fuel. The increasing dominance of DFDE tankers is shown in Figure 22.

There are more than 50 DFDE vessels in operation or under construction, and all the Qflex and Qmax related with the Qatari projects are SSD with re-liquefaction.

One steam turbine ship and four DFDE are to be equipped with re-liquefaction units which allow the operator to arbitrage between LNG and HFO/Diesel prices.

2.3.1.2. Containment Systems

There are two main containment systems: membrane (around 70% of in existence or on order ships) and spherical Moss (30% approximately).

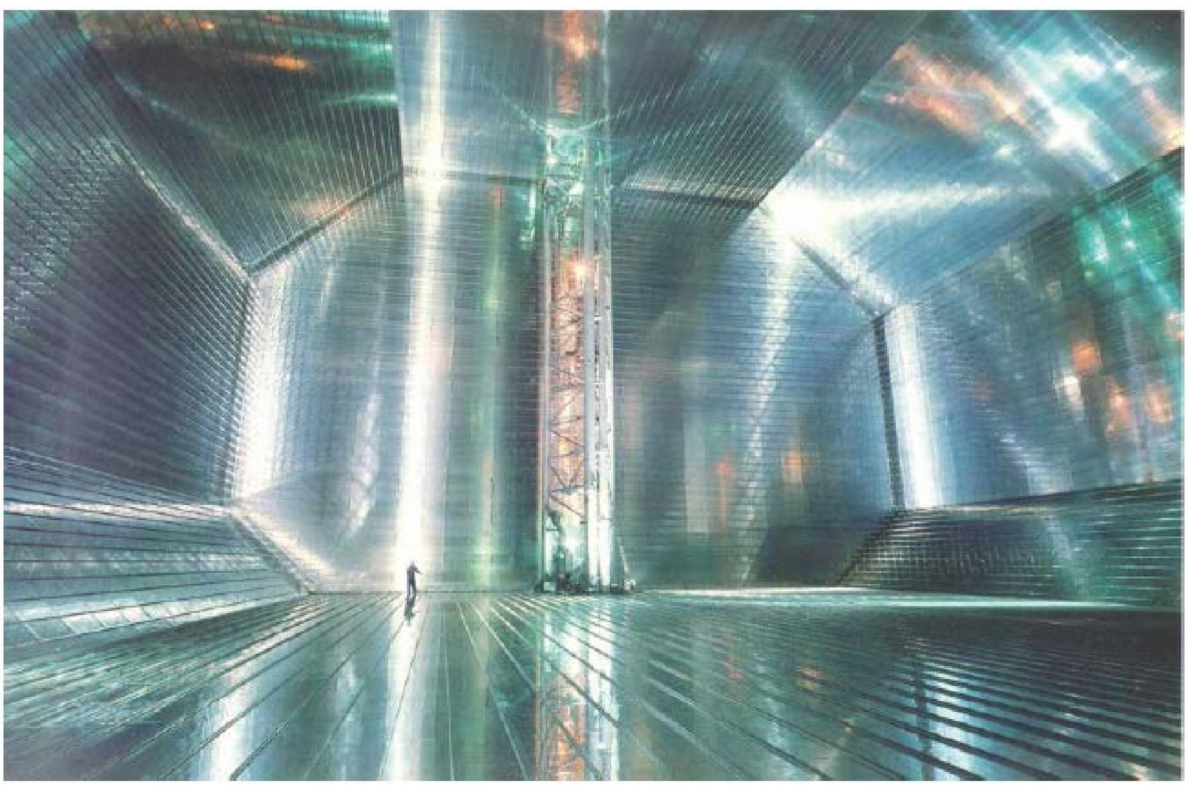
Figure 23 – Photo of Spherical Moss Vessel

Technological innovations have reduced the cost of building membrane types, and membrane ships have such advantages in trading as lower Suez Canal transit costs and faster cool down times.

However, the main advantage of the spherical Moss system is the reduction of sloshing issues, movement of the free surface of the LNG within a compartment of the vessel and internal fluid dynamics that interacts with the vessel and influences the dynamic stability of the ship, which are important mainly in rough sea conditions.

Figure 24 – Photo of Membrane Vessel

Figure 25 – Photo of Inside View of Membrane Tank



2.3.1.3. Ice Class & Winterised Designs

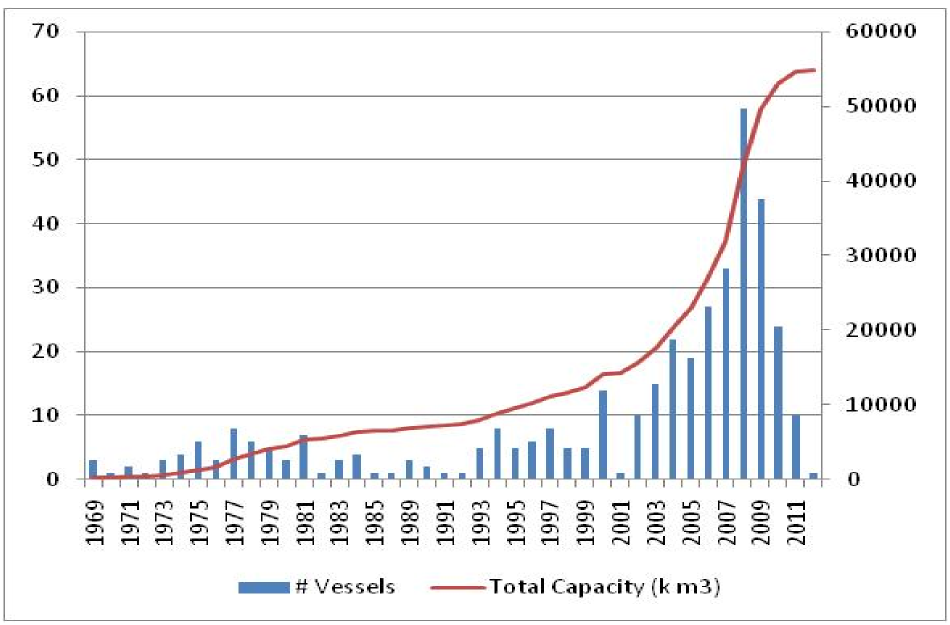
The LNG shipping sector has recently experienced an increasing number of ice class and winterized designs. All ships ordered by the Snohvit and Sakhalin projects feature such designs, as have some vessels recently commissioned for buyers in the Far East who anticipate creating trading advantages in short-term freight markets.

Winterised designs include deck machinery, heating equipment, extra strengthening of rudder and propeller tips, and thicker glass in portholes and on the bridge where observation wings are enclosed.

2.3.2. Tanker Completions and Capacities

The extension of the global fleet in the past decade has taken it to a total of more than 300 vessels at the end of 2008, with a combined capacity of nearly 50 Mcm. Since then, additions to the fleet have tapered off, although shipbuilding has increased once again following major drivers in the Asia Pacific region – economic recovery and the Fukushima accident.

Figure 26 – LNG Tankers Entering Service and Global LNG Shipping Capacity, Mcm

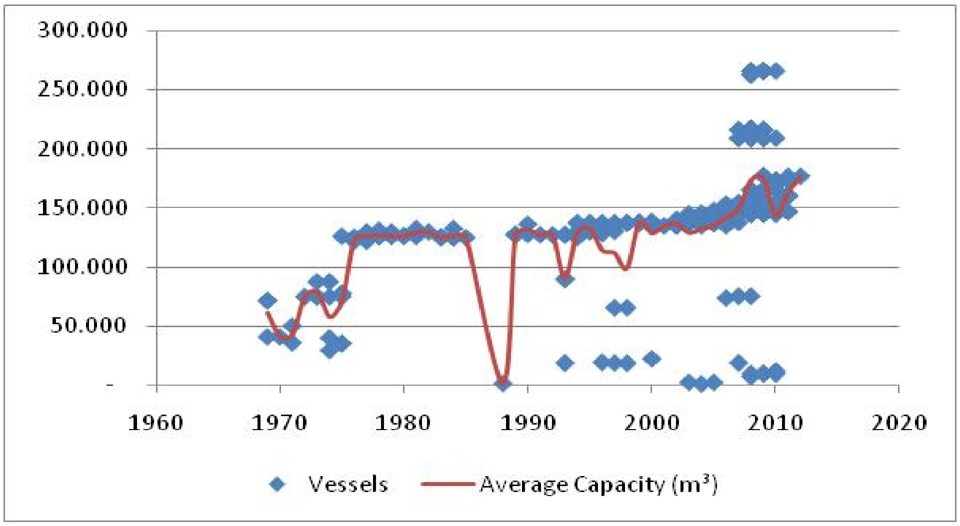


Historically, most LNG transport has been carried out in large-scale LNG carriers to ensure the most economical deliveries from liquefaction plants to buyers, distributors and end-users.

The industry has experienced a major step up in ship size, as shown in Figure 27. Capacities of the LNG carriers ranged from 80,000 to 135,000 m^3 until 2006, when LNG ships of 200,000 and 260,000 m^3 were constructed in conjunction with mega-trains in Qatar.

Substantial LNG supply expansion projects in Qatar have driven much of the increase in ship sizes. The Qatari projects (Rasgas and Qatargas) have already ordered 45 ships bigger than 200,000 m^3, 14 Qmax (263,000-266,000 m^3) and 31 Qflex (209,200-217,300 m^3). The reason behind this larger size is the further destinations expected for these volumes and the consequent savings in the LNG shipping.

Figure 27 – Trend in Capacity of LNG Ships, m^3



Regasification terminals are adapting their facilities to suit the dimension of these larger vessels. The physical restrictions include storage capacities, strength and length of the jetties, and fenders and mooring equipment. The physical geography of the ports (water depth and manoeuvring space) is another issue in some locations as river terminals. owever, the Qmax and Qflex have experienced difficulties unloading in some regasifications terminals.

Nowadays, there are all over the world around 50 terminals accepting Q flex and nearly 20 terminals under construction can accept them, as well as other 10 more terminals approved or proposed. They are listed as follows:

- Terminals in operation that can receive Qflex:
  - North America: Canaport, Altamira, Costa Azul, Manzanillo, Cameron, Cove Point, Elba Island, Freeport, Golden Pass, Gulf LNG Energy, Lake Charles, Sabine Pas.
  - South America: Baia de Guanabara, Pecem.
  - Europe: Aliaga, Barcelona, Bilbao, Cartagena, Dragon, Fos-Cavaou, Gate, Isle of Grain, Montoir-de-Bretagne, Sagunto, South Hook, Zeebrugge.
  - Middle East: Dubai.

  - Asia Pacific: Dalian, Dapeng, Rudong, Zhejiang, Dahej, Hazira, Nusantara, Chita, Futtsu, Higashi, Joetsu, Kawagoe, Negishi, Niigata, Ohgishima, Sakai, Senboku, Sodegaura, Incheon, Pyeongtaek, Tongyeong, Map Ta Phut.

- New terminals that will take Qflex:
  - North America: Aguirre, Jamaica –proposed-.
  - Europe: Dunkirk, El Musel, Polskie -under construction- and Fos Faster (Fos-sur-Mer 3), Shannon –proposed-.
  - Asia Pacific: Boryeong, Caofeidian, Hainan, Joetsu, Kita-Kyushu, Kochi, Lampung, Melaka, Samcheok, Shenzhen, Singapore, Tianjin, Zhuhai -under construction- and Guangxi, Jieyang, Lianyungang, Ningde –proposed-.

Figure 28 – Photo of QFlex and Standard Vessel

Qmax will probably also be delivered in some of these terminals, including Bilbao, Sabine Pass, Pyong-Taek, Incheon, Elba Island, Freeport, Tongyeong, South Hook, Gate and Golden Pass.

There are around 30 operational terminals and nearly 10 terminals under construction that could accept Q max, as well as other 7 more terminals approved or proposed.

However, the most likely trend in the size of tankers for the next several years is likely to be the Panamax size, i.e., maximum tanker size accepted in the Panamá Canal after the expansion, 175,000-180,000 m^3, at the same time that development of small LNG carriers has appeared as a way of addressing constraints and restrictions at numerous smaller ports.

2.3.3. Small-Scale LNG Tankers

The movement of liquefied gases by small carrier is an emerging sector of the LNG chain, and is served by a fleet of several tankers.

Capacity of small LNG carriers ranges between 500 m^3 and 12,000 m^3 and the cargo tank construction of small LNG carriers can be of prismatic design, membrane design or spherical design. Materials used for these cargo tanks can be aluminium, balsa wood, plywood, invar or nickel steel, stainless steel, with perlite and polyurethane foam.

Small LNG carriers are able to deliver cargoes to ports closer to the final customer and cover a wider range of market requirements. Small-scale LNG tankage is also expected to facilitate meeting ambitious air emission targets set by national, regional and international regulators, especially to the extent of greenhouse gas emission limitations.

This new type of LNG carriers will call on an increasing array of smaller terminals. This will allow a faster implementation of projects through out the LNG value chain and enable the use of LNG in a wider range of applications, e.g., LNG as fuel for ships, rail, trucks, and traditional gas markets (domestic, industrial, and power generation) in island and remotely-located continental communities. Capital costs for developing infrastructure is far lower than for large- scale LNG applications, and is often more economical and efficient that traditional pipelines. For instance small carriers of 10,000 m^3 can move up to 500,000 tons per year depending upon supply distances. The possibility of adjusting the infrastructure to the demand quickly is an advantage compared to the gas supply with pipelines or larger tankers. Small LNG carriers can operate within the supply chain in a relatively uncomplicated way, serving gas to customers for whom pipeline access is uneconomical. Additionally, the small tanker concept can enable producers to monetize stranded gas, thus exploit gas fields too small for traditional large-scale LNG.

As we have discussed above, there are several opportunities for small LNG carriers:

- Expanding demand
- Supplies to the areas without connection to gas pipelines systems
- Flexibility in supplies
- Less capital investment for carriers
- Balancing stocks and inventories
- Development of new markets
- Construction of new small terminals.

In Japan, the first small scale LNG carrier entered service in 2003 and their fleet had reached four such carriers by 2010. The customer in Japan uses this fleet of small LNG tankers to transport LNG which is loaded in the primary LNG regasification terminal to secondary ones, located 100 Km to 850 Km away, for domestic use.

The cargo tank containment system consists of two cylindrical pressurized stainless steel cargo tanks operating independently, each of 1,250 cubic meters in capacity. The installation of pressurized cargo tanks allows a widely used diesel engine to prevent boil off gas emissions during the voyage. Major characteristics of this small LNG carrier fleet are as follows:

- Gross Tonage: 2,950 tons
- Length: 89,3 meters
- Depth: 7 meters
- Full draft: 4.2 meters
- Capacity: 2,500 cubic meters
- Sea speed: 13 Knot

To summarize, the drivers behind small-scale LNG tankage include:

- Economical (fuel substitution, prices)
- Increasing availability of LNG
- Environmental (less air pollution)
- Diversification of gas sources
- Energy security
- Back up in plants and glass industry
- LNG as an alternative fuel (vehicles, trains, planes)
- Ship fuel (restrictions on emissions SOx, NOx, CO2).

2.3.4. LNG as a marine fuel and air quality considerations

To date, widespread use of LNG as fuel for propulsion aboard merchant ships has been common only on LNG tankers; most LNG carriers delivered until recently use boil-off from their cargo as fuel for steam boilers and propulsion.

In order to broaden its maritime use, the LNG industry and regional governmental and port authorities would need to develop infrastructure to store and supply LNG far more widely than at present, and most likely also assist by establishing incentives and contributing to practical solutions. As this evolution progresses, LNG will be best targeted toward relatively short distance shipping and, in the near term, aboard vessels trading between fixed ports and/or in areas where LNG fuel is conveniently available. Introducing LNG as fuel for shipping will also require wider port capabilities to control CO, NOx and Sox emissions. With such air quality measures in place, LNG would hold significant environmental advantages over diesel engines; likewise, LNG-fuelled shipping would minimize greenhouse gas (GHG) emissions.

Gas engines available today can be divided in two main categories:

- Dual fuel engines (e.g., Wärtsilä, Man)
- Lean-burn gas engine (e.g., Rolls Royce, Mitsubishi)

Achieving maximum reduction of air contaminants and GHGs from gas-fuelled vessels will require careful selection of engines and arrangements fit for case-specific applications and modes of operation, e.g. full load or frequent part load.

The actual degree of reduction of GHG and other air emissions in individual instances will be driven by the total efficiency of the chosen alternative. It should be noted here, however, that methane slip, i.e. incomplete combustion of methane in engine cylinders, would have to be prevented in order to minimize fugitive methane releases in the exhaust streams, which could threaten to negate the GHG advantages of gas as a fuel.

The European Union and the International Maritime Organization (IMO) are aiming for ambitious CO2 reductions in the 2020s and beyond. Consequently, emerging uses of LNG in marine transport shipping – otherwise a solution, as one of the most efficient and cleanest forms of transportation – will need to control emissions and prevent fugitive releases, else suffer regulatory challenges.

2.4. Regasification

Regasification is, simply, the opposite of liquefaction; it consists of warming LNG to the point where it becomes a gas. This is a process that occurs naturally at atmospheric temperatures (known as “boil off”), and is expedited by passing LNG through warmer media.

Regasification terminals are facilities built near the marketplace that receive and berth LNG tankers, offload and store the LNG, pump and vaporize the LNG into natural gas, and then send out the revaporized LNG (i.e,, natural gas) gas into the local pipeline network according to the requirements of the market.

Technologies used in the regasification process are relatively simple, and are far less costly than technologies used in liquefaction terminals. Unlike liquefaction, which is highly energy and capital intensive, regasification facilities represent the least costly step in the LNG value chain.

The main components in a regasification facility are:

- Tanker berth and unloading arms
- LNG storage tanks
- LNG pumping equipment
- Regasification system
- Boil off capture and return systems
- Metering and odorization systems

Each of the foregoing steps are discussed as follows:

2.4.1. Main components in a regasification facility

2.4.1.1. Tanker berth and unloading arms

The LNG is unloaded by activating pumps aboard the tanker and piping the LNG through the articulated arms connected to the ship manifold. An additional unloading arm recovers the boil off gas and sends it back to the tanker.

Currently, the offloading flow reference rate is about 12,000 m^3/h, thus it requires approximately 12 hours to unload a standard 140,000 m^3 vessel. More recently, flow rates have increased to 18,000 m^3/h in larger tankers.

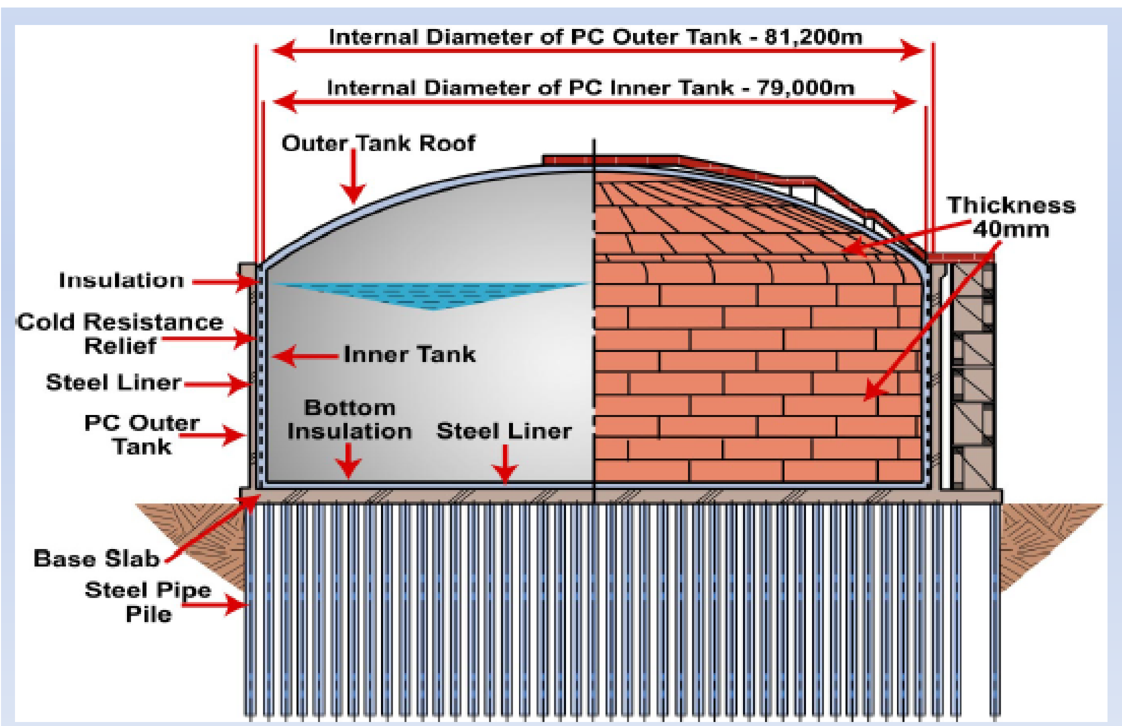
2.4.1.2. LNG storage tanks

The resident LNG storage capacity in a regasification terminal must be enough to unload ships without delay and should provide back-up storage to ensure supply to the market if a cargo is delayed. Storage may also be used for strategic purposes and to manage seasonal variations in local demand.

There are three main types of storage tanks:

- Above ground tanks with simple containment: the inner tank, typically nickel steel, contains liquid and vapour; and the outer tank, usually carbon steel, holds insulation but would not hold liquid if inner tank was breached.
- Above ground tanks with double containment: the outer tank, generally concrete would contain liquid in case of breach of inner tank, but vapour would escape. If the outer tank also holds vapour then it is a full containment tank.
- Buried or semi-buried (in-ground) tanks: more expensive than above ground tanks, are used when environmental or aesthetic considerations are paramount.

Figure 29 – Illustration of a Double-Wall Containment LNG Tank



Tanks may be filled from the top or the bottom to ensure that different qualities (and densities) of LNG are blended to avoid roll-over stratification phenomenon; if this occurs, pressures inside the storage tank may rise to excessive levels.

Due to the transference of heat inside the tank, the different layers (density and temperature) of LNG tend to equilibrium: upper layers tend to become denser as consequence of the evaporation of light gases and lower layers tend to become warmer and less dense as this liquid doen not evaporate but superheats because of the pressure of the upper layer. The interface between the two layers becomes unstable and mixes rapidly liberating the trapped heat and generating a large amount of vapor that may exceed the venting capability of the tank.

Tank sizes have increased from 40,000-50,000 m^3 in the first regasification terminals to the typical 150,000-180,000 m^3 currently. Currently, the largest LNG tanks have a capacity of 200,000 ^{m3}. Geometrically, the tanks are usually cylinders with a diameter between 60 and 90 m and a height in the range from 30 to 50 m.

2.4.1.3. LNG pumping equipment

Cryogenic submerged pumps send LNG at high pressure to the vaporizers. LNG is compressed before being gasified as it is more efficient to pump a liquid instead of a gas. After the regasification process, additional compression is not needed because the gas leaves that stage with sufficient pressure to be transported.

2.4.1.4. Regasification system (vaporization)

Vaporizers consist of heat exchangers where LNG returns to its regular steam phase at about 5ºC. There are four main types of vaporizers:

- <u>Open Rack Vaporizers (ORV)</u>. ORVs take sea water and flow it over the vertical tubes of the vaporizers in order to warm up the LNG. Generally this is the preferred choice where warm sea water is available. The decrease of the ocean temperature is about 5ºC and is usually limited by environmental legislation to minimize the impact on marine life. This is the most common (more than 70% of total vaporizers) system in the operational regasification plants.

- <u>Submerged Combustion Vaporizers (SCV)</u>. In SCVs, the hot fluid is water heated by natural gas combustion. LNG flows through a collection of tubes and is warmed. SCVs use more energy and create emissions (because of the fired gas) but there is no water discharge. The gas consumption is approximately 1.5%-2% of throughput. The capital expenditure is lower than for an ORV, but operational expenditures are higher. This system is usually chosen for use in cold locations and as back-up for ORV vaporizers.

- <u>Shell and Tube Vaporizers (STV)</u>. Shell and tube vaporizers are smaller and are most popular when the regasification terminal is “linked” with other facilities such as a power plant or a CHP facility.

- Air vaporizers. Air is used as the heat source in some regasification facilities located in warm climates, including in India and the Gulf of Mexico. The main advantage is lower cost, however there is a reduction in the throughput when outside temperatures fall low enough to necessitate back-up from SCVs and/or ORVs.

These two last systems are less common than ORV and SCV vaporization technologies.

2.4.1.5. Boil-off treatment

During offloading, storage and pumping, there is a heat contribution that changes the phase of a small amount of LNG to steam (boil-off). The LNG regasification terminal will, therefore, require a system to capture the boil-off gas and send it to the "reabsorber." During offloading, the captured boil-off is returned to the tanker and used to maintain operating pressures in the hold.

The boil-off gas can be fuelled in a SCV vaporizer or used for power generation. It is also possible to recover it in a reliquefier. Boil-off gas that is neither used for fuel nor reliquefied is flared.

Typical boil off rates are below 1%/day in a regasification terminal.

2.4.1.6. Regasification Summary

Typical capital costs. The breakdown of capital costs for a typical onshore LNG receiving terminal is shown in Figure 30:

Figure 30 – Capital Costs for Regasification

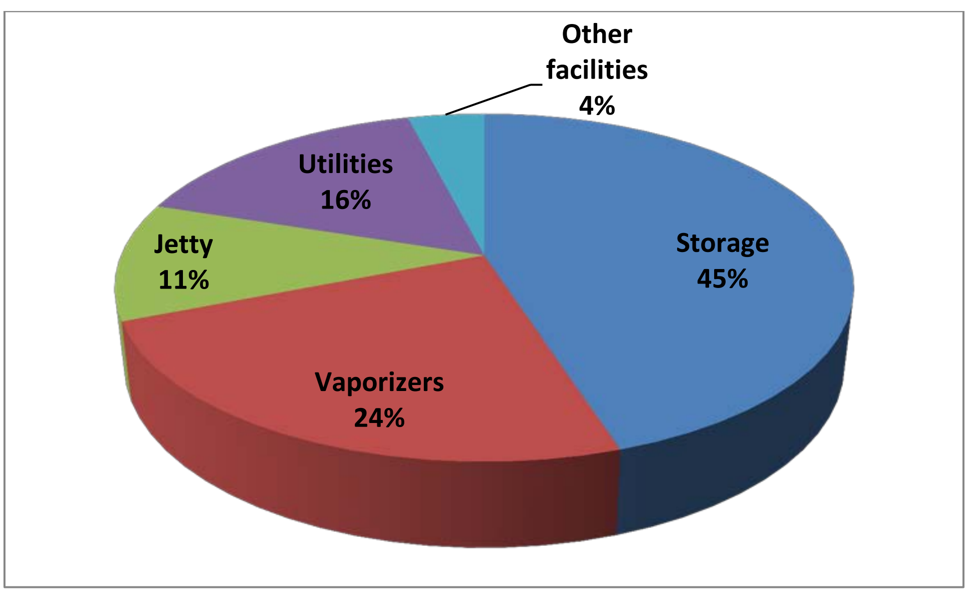
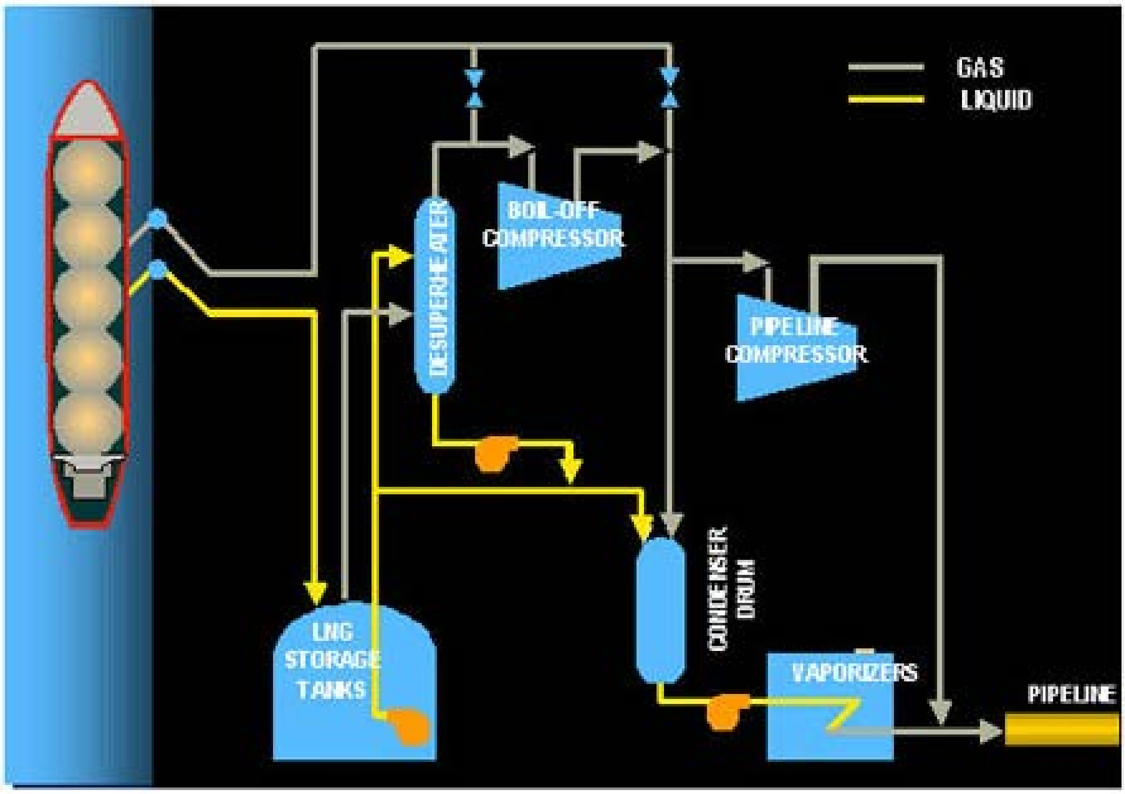
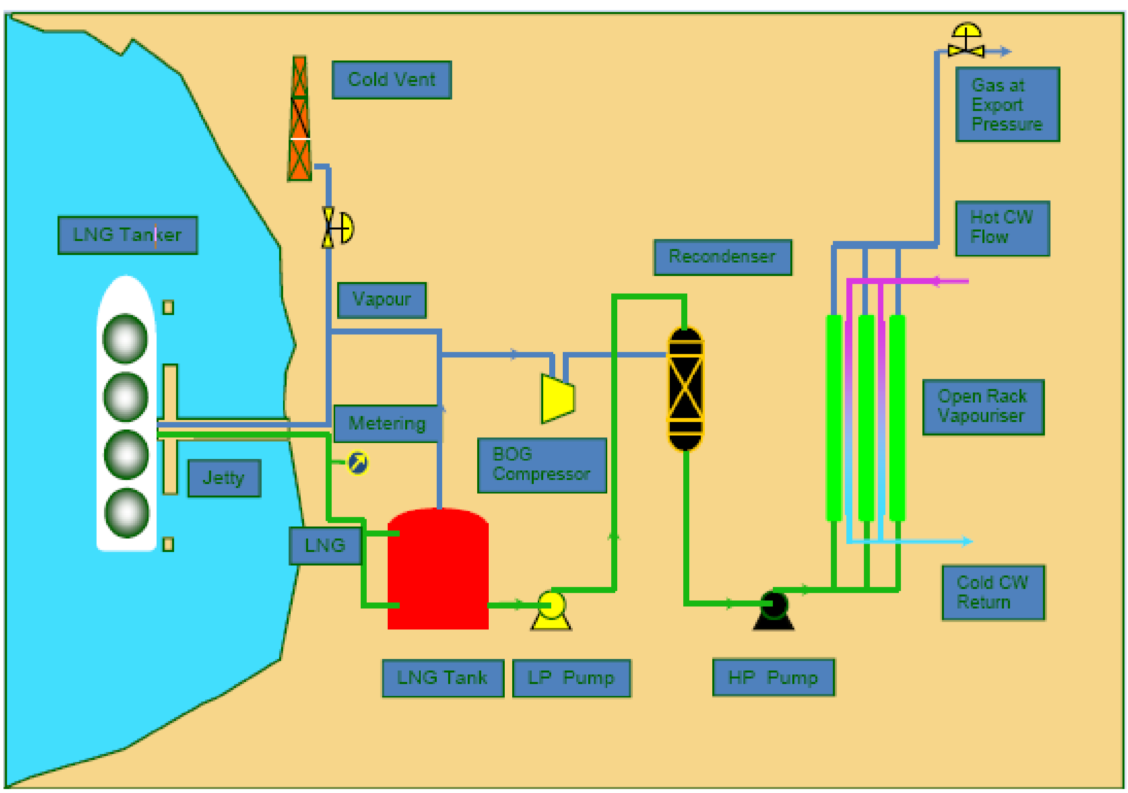


Figure 31 – Regasification Plant Process Illustrations



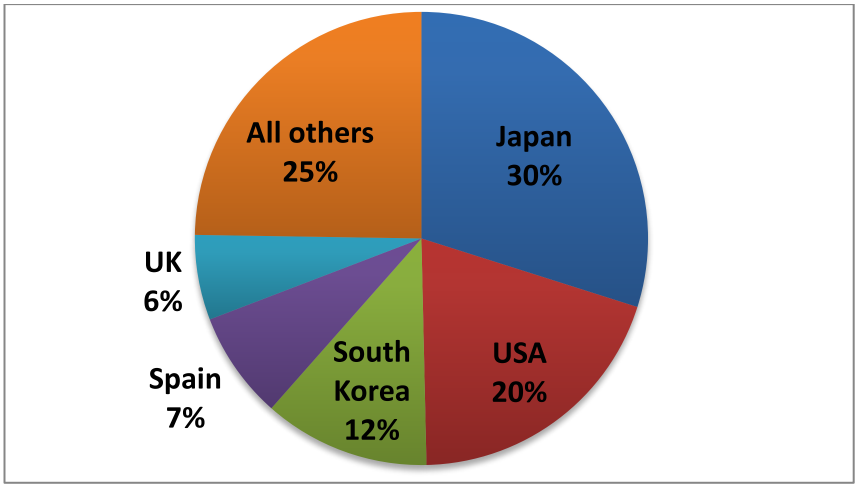


2.4.2. Global regasification capacity

Global regasification capacity in operation presently is approximately 638 mtpa (at year-end 2012). Regasification capacity operations and expansions are summarized in Table 11 through Table 14 by facility status, basin, region and country.

More than 75% of the world's regasification capacity is located within the leading five countries in this respect – Japan holds 30% of global regasification capacity; the US, 20%, South Korea,12%; Spain, 8%, and the UK, 6% (see Figure 32).

Figure 32 – Top Five LNG Regasification Capacity Holders, 2011



Of the total amount, 50% operates in Japan and the U.S., although it should be noted that these two countries place totally opposite reliance on LNG deliveries through their facilities – Japan derives 98% of its gas supplies through its 35 LNG regasification plants, while the North Americans import relatively small quantities.[13]

Table 11 – Nominal Regasification Capacity, by Facility Status (mtpa)

Status	2010	2011	2012	2013	2014	2015	2020	2025	2030
Existing	557,7	598,7	637,7	655,1	650,7	648,7	648,7		
Under construction				4,9	28,8	63,7	84,2		
FEED Completed					2,2	13,1	32,7		
In FEED					1,5	3,0	3,0		
Pre-FEED				1,0	11,0	18,8	87,9		
Proposed									
Decommissioned	3,0								
TOTAL	560,7	598,7	637,7	661,0	694,2	747,3	856,5		

Source: PFC Energy and author's elaboration

13 Except through the Everett and Canaport facilities which, together, supply 24% of New England's gas requirements.

Table 12 – Nominal Regasification Capacity, by Basin (mtpa)

Basin	2010	2011	2012	2013	2014	2015	2020	2025	2030
Atlantic-Mediterranean	243,3	272,5	297,6	300,1	306,7	316,5	346,0		
Middle East	3,9	6,7	6,8	8,5	8,5	11,8	27,0		
Pacific	313,5	319,5	333,4	352,3	379,0	419,0	483,4		
TOTAL	560,7	598,7	637,7	661,0	694,2	747,3	856,5		

Source: PFC Energy and author's elaboration

Table 13 – Nominal Regasification Capacity, by Region (mpta)

Region	2010	2011	2012	2013	2014	2015	2020	2025	2030
East Asia	289,1	293,0	299,4	307,7	320,8	345,4	366,6		
South & Southeast Asia	13,5	15,1	20,0	30,9	43,1	54,0	92,2		
Middle East & North Africa	3,9	6,7	6,8	8,5	8,5	11,8	27,0		
Europe	114,3	129,7	138,1	139,3	141,1	148,8	174,7		
North America	127,9	139,4	156,3	157,8	157,8	159,6	162,7		
South America	12,0	14,8	17,1	16,8	23,0	27,7	28,9		
							4,4		
TOTAL	560,7	598,7	637,7	661,0	694,2	747,3	856,5		

Source: PFC Energy and author's elaboration

Table 14 – Nominal Regasification Capacity, by Country (mtpa)

Country	2010	2011	2012	2013	2014	2015	2020	2025	2030
Argentina	3,0	5,3	7,5	7,5	7,5	7,5	7,5		
Bahrain							3,0		
Bangladesh							3,7		
Belgium	6,5	6,5	6,5	6,5	6,5	6,5	6,5		
Brazil	5,5	5,5	5,7	6,8	11,6	11,6	9,7		
Canada	7,5	7,5	7,5	7,5	7,5	7,5	7,5		
Chile	3,4	3,9	3,9	2,5	3,9	8,4	9,0		
China	12,3	14,0	18,8	25,3	36,3	52,6	66,2		
Dominican Republic	1,7	1,7	1,7	1,7	1,7	1,7	1,7		
France	15,7	17,2	17,2	17,2	15,4	16,9	26,6		
Greece	3,3	3,3	3,3	3,3	3,3	3,3	5,2		
India	13,5	13,5	13,5	17,4	24,8	31,6	52,1		
Indonesia			1,6	3,7	4,0	7,2	7,2		
Ireland							3,1		
Israel			0,1	1,8	1,8	1,8	1,8		

Country	2010	2011	2012	2013	2014	2015	2020	2025	2030
Italy	7,5	8,3	8,3	8,3	11,0	11,0	16,8		
Jamaica							1,2		
Japan	173,9	175,0	176,7	178,4	180,4	184,9	185,4		
Jordan						2,9	3,5		
Korea	90,1	91,1	91,1	91,1	91,1	95,1	100,0		
Kuwait	3,7	3,7	3,7	3,7	3,7	3,7	11,2		
Lithuania						2,2	2,2		
Malaysia				2,5	3,8	4,2	8,4		
Mexico	12,9	12,9	15,4	16,6	16,6	16,6	16,6		
Morocco									
Netherlands		2,4	8,7	8,7	8,7	8,7	8,7		
Norway									
Philippines							4,0		
Poland						2,1	3,6		
Portugal	3,8	3,8	4,6	5,8	5,8	5,8	5,8		
Puerto Rico	0,6	0,6	0,9	1,1	1,1	3,0	4,9		
Singapore				2,3	5,6	6,0	6,0		
South Africa							4,4		
Spain	37,2	41,7	42,8	42,8	43,6	45,3	46,3		
Sweden		0,1	0,3	0,3	0,4	0,5	0,5		
Taiwan	12,9	12,9	12,9	12,9	12,9	12,9	14,9		
Thailand		1,6	4,9	4,9	4,9	4,9	9,9		
Turkey	8,7	8,7	8,7	8,7	8,7	8,7	8,7		
UK	31,7	37,7	37,7	37,7	37,7	37,7	40,7		
United Arab Emirates	0,1	3,0	3,0	3,0	3,0	3,3	7,5		
Uruguay						0,2	2,7		
US	105,4	116,8	130,9	130,9	130,9	130,9	130,9		
Vietnam							1,0		
TOTAL	560,7	598,7	637,7	661,0	694,2	747,3	856,5		

Source: PFC Energy and author's elaboration

The world's regasification capacity is much higher than its liquefaction capacity. As a consequence, the average utilisation rate of regasification terminals is below 50%. The U.S. has become the last resort market, with a regasification overcapacity (regasification rates lower than 5%).

2.5. Floating LNG

2.5.1. Floating Regasification LNG

The difficulties of obtaining permission to build on-shore LNG reception facilities, mainly but not only in the North American coasts led to the development of several various designs of floating LNG regasification projects.

2.5.1.1. FSRU

A floating LNG regasification vessel (commonly known as FSRU – Floating Storage and Regas Units) can load, transport, store and regasify LNG before delivering the natural gas to the market.

It can be operated either intermittently as a conventional trading ship delivering its own cargoes, or as a semi-permanent mother-ship processing supplies received by way ship-to-ship transfers from conventional LNG carriers.

The floating LNG regasification projects involve taking conventional regasification technology and placing it on a floating structure, what can be made in different ways.

- Energy Bridge Regasification Vessels (EBRV): developed by Excelerate, with capacities from 138,000 m^3 to 151,000 m^3.
- Shuttle Regasification Vessels (SRV): developed by Hoegh LNG and Mitsui OSK, with capacities of 145,300 m^3.
- Conversion of conventional tankers: developed by Golar LNG in markets requiring a fast delivery solution, mainly in new and seasonal LNG markets where the demand is not yet enough to justify the construction of a regasification facility. This conversion usually takes around 9 months.

Typically, a membrane containment will be used in a more benign maritime conditions with the spherical Moss for more exposed locations.

Depending on the port location, availability of storage, total transport distance and volumes, the regas vessel can be stationary and receive cargos from conventional LNG vessels, or it can be a shuttle vessel that picks up its own cargos and go to the receiving location and regas the cargo. Initially, there was a clear distinction between a stationary regas vessel labelled as Floating Storage and Regas Unit and the shuttle vessel labelled Shuttle & Regas Vessel. More customers now prefer flexible regas vessels that can act in both modes of operation.

2.5.1.2. Regasification

There are two main systems that can be used independently or combined:

- Open loop mode: relatively warm seawater is used as a heat source and passed through the heat exchangers causing the vaporisation of the LNG. It is not applicable for water temperatures below 7ºC because during the process the temperature of the sea water is lowered by approximately 7ºC. It has lower operating costs, but in some locations environmental restrictions are applied.
- Closed loop mode: around 1,5% of boil off gas is used to heat fresh water that is circulated through the heat exchangers.

2.5.1.4. Offloading

There are two ways for offloading regasified volumes from a floating LNG regasification project:

- Deepwater port facilities: consist of a subsurface buoy to allow tankers to deliver regasified volumes into a subsea pipeline via a flexible riser. The bouy also acts as a mooring for the vessels.
- Onshore dockside receiving point: generally consist of high pressure unloading arms at the jetty connected to a pipeline offering direct access to the markets. The construction time is usually shorter (about 1 year) than other regasification facilities.

2.5.1.5. Comparison Floating vs Conventional Regasification

There are several advantages and disadvantages when considering the utilization of Floating Regasification instead Conventional Regasification, what makes difficult to generalize the most appropriate selection, which will depend on the particularities of each project.

The regasification capacity of FSRUs currently in operation range from 255 mmcfd to 690 mmcfd, which is comparable with many conventional onshore terminals, but there are limitations in utilisation, storage availability and the ability to expand either storage or regasification capacity. The effective regasification capacity of floating LNG regas can be increased by utilising two vessels at the same place.

The main significant characteristics of FSRU and Conventional Regasification project are as shown in Table 15.

Table 15 – Main significant differences between FSRU and Conventional Regasification

	FSRU	Conventional Regasification
Costs	Lower CAPEX, Higher OPEX	Higher OPEX, Lower CAPEX
Project Lead Time	Faster, possible in less than 1 year	More difficult permitting process
Infrastructure	Considerably less required: no storage tank or port infrastructure required	High CAPEX associated with storage tanks (usually 1/3 of total investment)
Unloading	Extra unloading time which reduces the utilisation rate	14-24h (approximately 10,000 m3/h)
Delivery profile	The delivery rate is the send out rate while the vessel is unloading or zero until the next tanker arrives. However, this issue could be tackled implementing ship to ship transfers	LNG can be regasified from storage tank when required by the market
Flexibility	The infrastructure can be moved to a different location	
Quality	More difficult to incorporate blending or nitrogen injection	

Source: Author's elaboration

2.5.1.6. Projects

Table 16 – Existing FSRU Projects

Project Name	*Location*	*Proponents*	*Design*	*Shipping Requirement*	*Nominal/Peak Capacity (mmcfd)*	*Start up*
Gulf Gateway	Louisiana, USA	Excelerate Energy	Offshore Deepwater Port	EBRVs	500/690	Mar 2005
Teeside GasPort	Teeside, UK	Excelerate Energy	Dockside Receiving Point	EBRVs	400/600	Feb 2007
Northeast Gateway	Massachusett, USA	Excelerate Energy	Offshore Deepwater Port	EBRVs	400/800	Feb 2008
Bahía Blanca	Bahía Blanca, Argentina	Excelerate Energy, Repsol-YPF, Enarsa	Dockside Receiving Point (parallel discharge)	STS at jetty conventional LNG tanker to EBRV	400	May 2008
Pecem	Ceara, Brazil	Petrobras, Golar LNG	Dockside Receiving Point (parallel discharge)	STS at jetty from conventional LNG tanker to converted Golar Spirit	255	Dec 2008

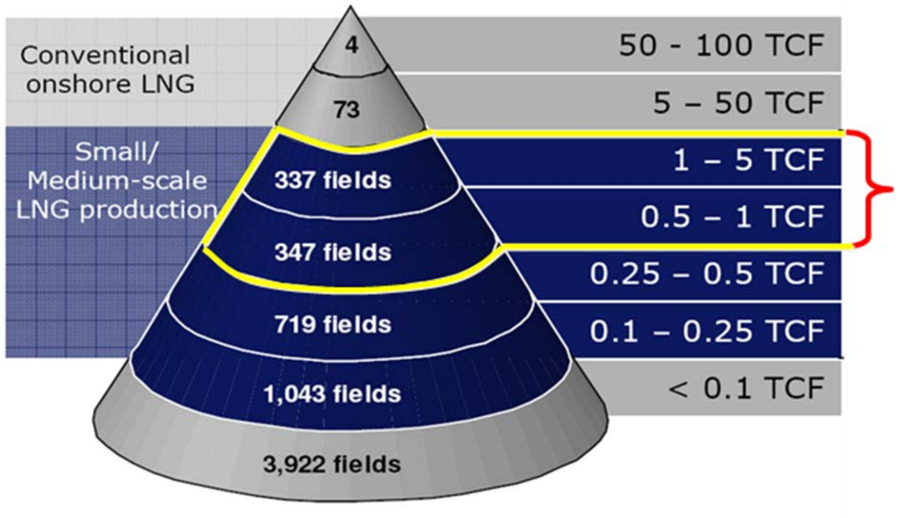
Project Name	*Location*	*Proponents*	*Design*	*Shipping Requirement*	*Nominal/Peak Capacity (mmcfd)*	*Start up*
Adriatic LNG	Rovigo, Italy	ExxonMobil, Qatar Petroleum, Edison	Gravity Based Structure	Deliveries by conventional LNG tankers to GBS	818	Apr 2009
Baia de Guanabara	Rio de Janeiro, Brazil	Petrobras, Golar LNG	Dockside Receiving Point (parallel discharge)	STS at jetty from conventional LNG tanker to converted Golar Winter	521	May 2009
Mina Al Ahmadi GasPort	Kuwait	KNPC, Excelerate Energy	Dockside Receiving Point	STS at jetty from conventional LNG tanker to EBRV	500	Mid 2009
Neptune LNG	Massachusett, USA	GDF Suez	Offshore Deepwater Port	SRVs	400/750	Dec 2009
Dubai LNG	Dubai, UAE	DUSUP, Shell, Golar LNG	Dockside Receiving Point	STS at jetty from conventional LNG tanker to converted Golar Freeze	480	Jul 2010
Mejillones	Antofagasta, Chile	GDF, Codelco	Dockside Receiving Point	BW Suez Brussels,(Leif Hoegh FSRUs)	219	Oct 2010
Escobar	Buenos Aires, Argentina	Excelerate Energy, Repsol-YPF, Enarsa	Dockside Receiving Point (parallel discharge)	STS at jetty from conventional LNG tanker to EBRV	500	May 2011
OLT Offshore LNG Toscana	Livorno, Italy	E.ON, Golar	Offshore Deepwater Port	STS from conventional LNG tanker to converted Golar Frost	363	2012

Source: WoodMackenzie and author's elaboration

2.5.2. Floating Liquefaction LNG

The main aim of LNG Floating Production, Storage and Offloading (LNG FPSO) is monetising stranded gas fields that are currently considered uneconomic to develop because of their small size and/or remoteness from markets. It could be also a temporary solution while onshore liquefaction facilities are under evaluation.

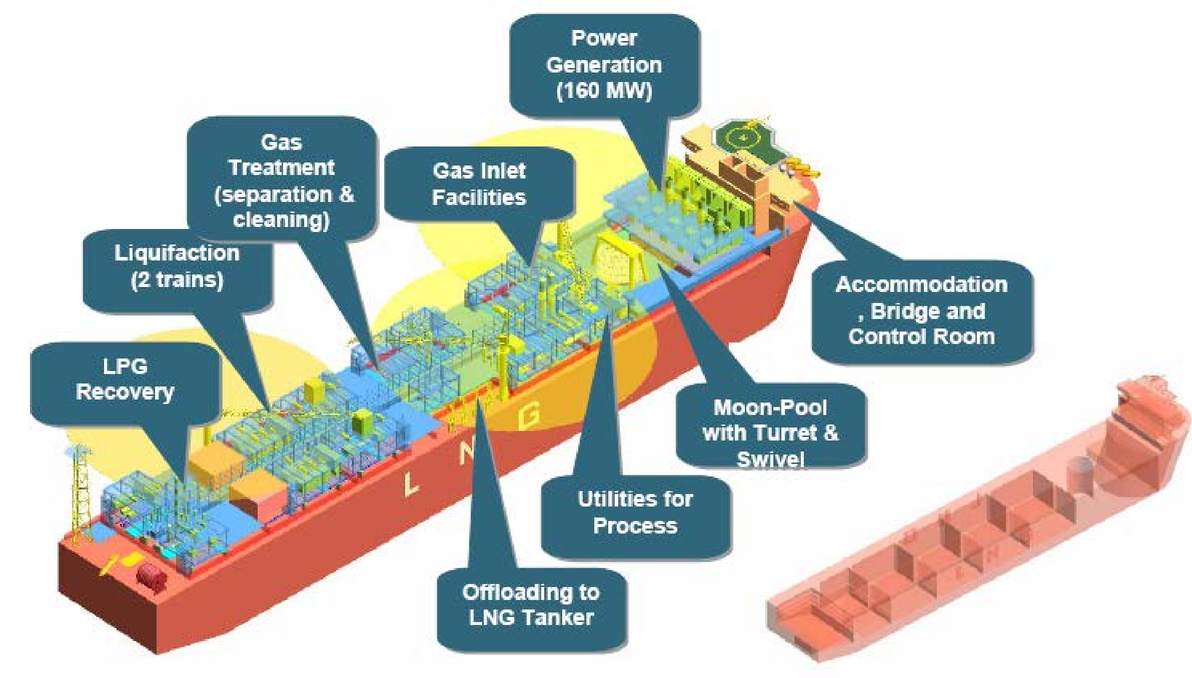
Figure 33 – Floating LNG niche



2.5.2.1. Technology

The main challenge is placing conventional liquefaction and fitting all the components on a floating structure. Another key factor is the storage of condensates and LPG. The preferred containment type for LNG storage is the SPB (Self Supporting Prismatic type B) technology, which does not have any filling restriction, is resistant to sloshing and utilises the deck space more efficiently. This is considerably more expensive than the conventional membrane or spherical designs.

Figure 34 – Floating LNG lay out



2.5.2.2. *Offloading*

LNG offloading from the FLNG vessel to a LNG tanker is another key consideration, being side-by-side (SBS) or Tandem mooring the main proposed systems. The SBS will be the most suitable option in areas with benign sea conditions and Tandem system in harsher sea environments.

2.5.2.3. *Comparison Floating vs Conventional Liquefaction*

The main significant characteristics of FSRU and Conventional Regasification project are as shown in Table 18.

Table 17 – Main significant differences between LNG FPSO and Conventional Liquefaction

	LNG FPSO	Conventional Liquefaction
Costs	Lower CAPEX, Higher OPEX	Higher CAPEX Lower OPEX
Project Lead Time	Faster than conventional	More difficult permitting process
Infrastructure	Considerably less required: no lengthy pipelines or port infrastructure required	Big logistical issues staffing and supporting development of projects
Financing	Unproven technology adds more risk	Long-term contracts by high creditworthy sellers & buyers
Security	Offshore location and/or compact size make facility easier to protect	Harder to protect, particularly onshore pipelines
Flexibility	The infrastructure can be moved to a different location	Fixed infrastructure
Storage	Limited storage. Stability and damage risk with certain tank containment systems.	High capital cost associated
Loading	Could be affected by adverse environmental conditions	Generally never a problem in a sheltered port
Environment	Minimizes fixed infrastructure and environmental impacts	Larger footprints

Source: Author's elaboration

2.5.2.4. *Projects*

There is a growing interest around in Floating LNG supply proposals in the last years and the main oil and gas corporation are developing their own projects, targeting stranded gas fields in a number of locations as Australia, Nigeria, PNG, Indonesia, Cameroon, Egypt and Brazil. The first project to take a Final Investment Decision has been Prelude in 2011 led by Shell in Australia.

The proposed LNG FPSO are shown in Table 19.

Table 18 – Proposed LNG FPSO Projects

Project Name	Basin	Country	Owner	Capacity (mmtpa)	Status	Announced Start
Pacific Rubiales FLNG	Atlantic	Colombia	Pacific Rubiales	0,5	Under Construction	2015
Petronas FLNG	Pacific	Malaysia	Petronas	1,2	Under Construction	2015
Prelude FLNG	Pacific	Australia	Shell, CPC, Inpex, KOGAS	3,6	Under Construction	2016
Rotan LNG	Pacific	Malaysia	Petronas, MISC, Murphy Oil	1,5	FEED Completed	2015
Lavaca Bay LNG Phase 1	Atlantic	US	Excelerate Energy	4	FEED Completed	2018
Lavaca Bay LNG Phase 2	Atlantic	US	Excelerate Energy	4	FEED Completed	N/A
Tamar LNG	Middle East	Israel	DSME, D&H, NextDecade	3	In FEED	2017
Abadi LNG	Pacific	Indonesia	INPEX, Shell	2,5	In FEED	2018
Cash Maple LNG	Pacific	Australia	PTT	2	Pre-FEED	2019
Scarborough LNG	Pacific	Australia	ExxonMobil, BHP Billiton	6,5	Pre-FEED	2020
Main Pass Energy Hub	Atlantic	US	McMoran Exploration, United LNG	4x6	Proposed	2017
Mozambique FLNG	Pacific	Mozambique	KOGAS, Galp, ENH, CNPC, Eni	5	Proposed	2017
Western Canada LNG	Pacific	Canada	Altagas, Idemitsu	2	Proposed	2017
Bonaparte LNG	Pacific	Australia	GDF Suez, Santos	2	Proposed	2018
African LNG	Atlantic	Nigeria	Gasol PLC	1,5	Proposed	N/A
ConocoPhillips Timor Sea FLNG	Pacific	Australia	ConocoPhillips	2,5	Proposed	N/A
Crux LNG	Pacific	Australia	Shell, Nexus Energy, Osaka Gas	2	Proposed	N/A
Iraq LNG	Middle East	Iraq	South Gas Co, Shell, Mitsubishi	4	Proposed	N/A
Shimshon LNG	Middle East	Israel	ATP Oil&Gas	N/A	Proposed	N/A
Sunrise LNG	Pacific	Australia	ConocoPhillips, Shell, Osaka Gas, Woodside	4	Proposed	N/A
Timor Sea Flex LNG Project	Pacific	Timor-Leste	Flex LNG	1,5	Proposed	N/A

Source: WoodMackenzie and author's elaboration

2.6. Market Technologies

The final market segment in the LNG value chain consists of the end-use markets in which vaporized LNG is consumed as natural gas. This section is a review that focuses on industrial process and feedstock uses, high-efficiency electricity generation, direct gas use in buildings, and natural gas vehicles.

2.6.1. Industrial Process and Feedstock Technologies

Natural gas has a multitude of industrial uses; indeed, industry is the largest gas-consuming sector globally.

Major industrial applications include:

- Chemical feedstocks – base ingredient for plastics, fertilizers, anti-freeze, fabrics and more products
- Form-value applications that take advantage of the unique flame properties of gas, e.g., metal treatment, glass
- Conversion to liquid fuel forms (gas-to-liquids, or GTL), especially for manufacture of such vehicle fuels as clean diesel, methanol, and others
- In-plant steam and electricity generation
- Industrial heating, cooling, cooking.

Major gas-consuming industries include:

- Pulp and paper
- Primary metals, e.g., iron and steel, and metal fabrications
- Chemicals, petrochemicals, petroleum refining, e.g., plastics, paint (see above)
- Stone, clay and glass
- Food processing industries.

Natural gas is also used for waste treatment and incineration, drying and dehumidification, and numerous municipal uses.

Natural gas absorption systems are also being used extensively in industry to heat and cool water in an efficient, economical, and environmentally sound way.

Natural gas liquids (NGLs) are also widely used as a feedstock for the manufacturing of a number of chemicals and products. Gases such as butane, ethane, and propane are extracted from natural gas to be used as a feedstock for such products as fertilizers and pharmaceutical products.

Increasingly, an important industrial use of natural gas involves conversion to vehicle fuels in processes aimed at replacing petroleum-based fuels that can be distributed through existing liquid fuel supply chain steps and stored conveniently aboard vehicles, including automobiles, trucks, aircraft, and rail and marine vehicles.

2.6.2. Electricity generation

Natural gas has become the fuel of choice in new thermal power plants because of its clean-burning nature compared with coal, in compliance with regulations aimed at reducing greenhouse gas (GHG) emissions. For an equivalent amount of heat, burning natural gas produces about 30% less carbon dioxide than burning petroleum and about 45% less than burning coal.

In addition, gas-fired power plants require lower initial capital investments than most other generators, occupy the least land area, and may be engineered, planned and constructed in far less time.

Natural gas fired electricity generation is increasing dramatically in the last years and this trend is expected to continue, especially with anticipated completions of numerous new, high-efficiency combined-cycle combustion units globally.

The main power plants using natural gas are:

- Steam generation units. The most basic natural gas-fired power plant is a steam generation unit, where gas or other fossil fuels are burned in a boiler to heat water and produce steam, which then turns a turbine to generate electricity. These basic steam generation units have fairly low energy efficiency (typically 33 to 35 percent of the thermal energy used to generate the steam is converted into electrical energy).

- Gas turbines (also referred to as simple- or single-cycle gas turbines). In these types of units, instead of heating steam to turn a turbine, hot gases from burning fossil fuels (particularly natural gas) are used to turn the turbine and generate electricity. Gas turbine and combustion engine plants are traditionally used primarily for peak-load demands, as it is possible to quickly and easily turn them on from start-up to full operation, e.g., in 10-20 minutes. These plants have increased in popularity due to advances in technology and the availability of natural gas. However, they are still often no more efficient (and traditionally slightly less efficient) than large steam-driven power plants.

- Combined-cycle combustion turbines (CCCT) or combined-cycle gas turbines (CCGT). Many new natural gas-fired power plants are 'combined-cycle' units. These generating plants include both a gas turbine and a steam turbine, all in one facility. The gas turbine operates in much the same way as a normal gas turbine, using the hot gases released from burning natural gas to turn a turbine and generate electricity. The waste heat from the gas turbine generates steam that is used to produce electricity much like a steam unit. Because of this efficient use of the heat energy released from the natural gas, combined-cycle plants are much more efficient than either steam or gas turbines alone, and can achieve efficiencies of up to 50% to 60%. Combined-cycle power generation using natural gas is thus the cleanest source of power available using fossil fuels because they take advantage of the low-carbon combustion of natural gas together with the high efficiency of the CCGT. Other advantages of gas fired combined cycles are lower CAPEX, easier permitting process and shorter construction time.

Figure 35 – Photo of a Combined-Cycle Gas Turbine (CCGT) Plant

- Combined heat and power (CHP). Natural gas is used to generate the electricity required in a particular industrial or commercial setting, thus the excess heat and steam produced from this process is harnessed to fulfill other energy needs on-site or in the immediate vicinity.

- Distributed generation (DG). Placement of small-scale electric generation units at residential, commercial or industrial sites – rather than reliance on large and centralized power plants – is feasible in many locations, if powered by natural gas.

Some advantages of distributed generation include higher reliability, avoiding transmission line losses, and direct choice of purchased fuel. Such medium-sized establishments as universities, hospitals, commercial complexes and industrial plants commonly use DG. Efficiencies of this type of electricity generation are comparable to centralized power plants, depending in the technology employed, e.g., whether simple-cycle gas turbine, steam generation units, or CCGTs. In addition, DG may enable deployment of a number of other technologies for on-site power generation, e.g., fuel cells, microturbines or industrial natural gas fired turbines.

- Industrial co-firing. Natural gas is often used to supplement combustion of such other fuels as coal, wood or biomass energy. Selectively adding natural gas to the combustion process can have two positive effects: reducing air emissions and improving efficiency.

In addition to the foregoing technologies, natural gas-fired electricity generation is commonly in use to compensate for uncertainties in dispatch of wind and solar-powered generation. In these kinds of applications, LNG has the particular advantages of a liquid, rather than a gas, in enabling quick start-up of CCGT plants without delays in nominating and dispatching pipeline gas. Due to the possibility of a close storage and a rapid process of regasification, it is possible to use the gas without prejudice of the pressure on the pipeline and avoiding congestion restrictions on the gas network. In Spain, a strategy has been undertaken of co-locating gas-fired CCGT units with LNG receiving terminals, thus enabling world-leading wind-farm "load-following" capabilities based on using gas to generate electricity on demand.

2.6.3. Residential and commercial uses

The main commercial and residential uses of natural gas include space heating, water heating, cooling and cooking. Millions of households and hundreds of thousands of larger buildings are connected to low-pressure natural distribution networks throughout the globe. This is especially true throughout the UNECE region – i.e., in Western and Eastern Europe, countries of the former Soviet Union, and in North America – and in Japan and other highly economically developed parts of the Asia-Pacific region. For example, market penetration of natural gas in housing is especially high in the U.S., where 60 million homes use natural gas primarily for space heating and hot water.

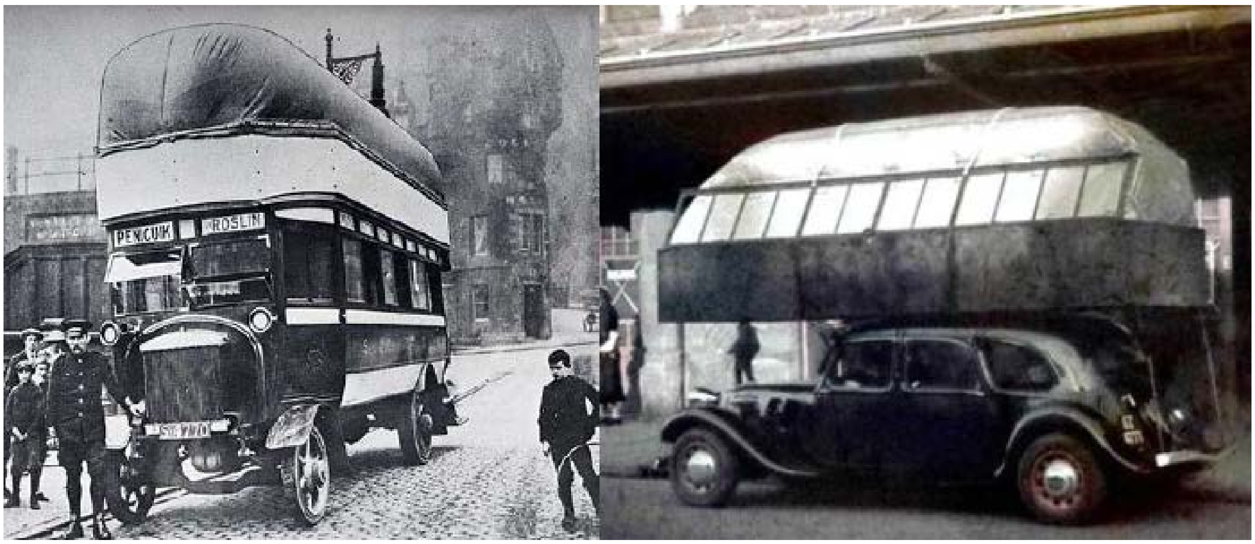
Growth in natural gas distribution to residential and commercial customers is taking place particularly rapidly in China and India, for both economic and environmental quality reasons.

2.6.4. Natural gas vehicles (NGVs)

A natural gas vehicle (NGV) is an alternative fuel vehicle that uses compressed natural gas (CNG) or liquefied natural gas (LNG) instead of conventional petroleum-based vehicle fuels.

NGVs were first developed in Europe nearly 100 years ago in response to war-caused fuel shortages. Approximately 13-15 m^3 of uncompressed gas was stored in large bags above the vehicle, as in Figure 34, giving a range of 50-60 km.

Figure 36 – Gas-Bag Vehicles in Scotland and Netherlands

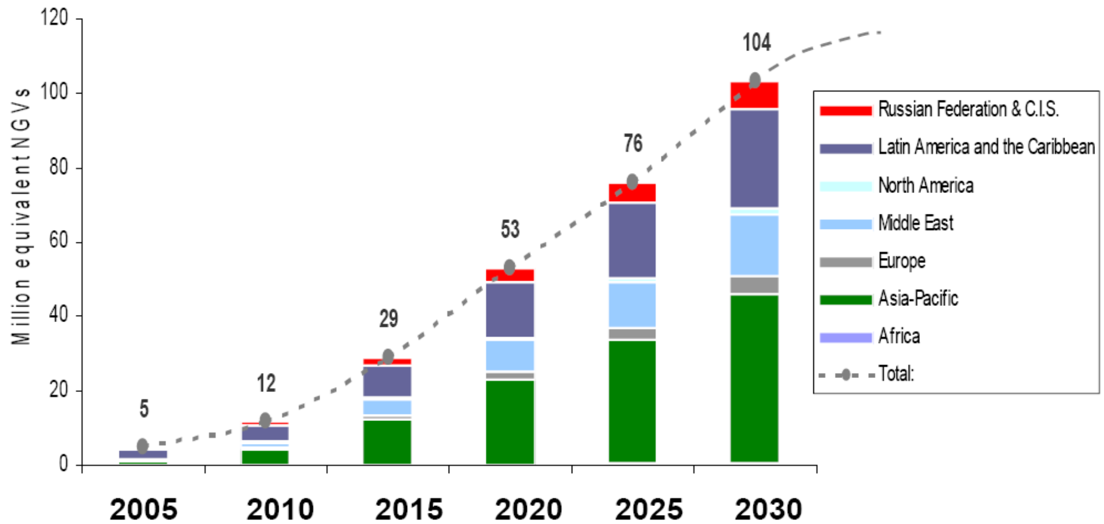


Later, in the 1940s and 1950s, vehicles operating on gas gained some acceptance in Europe, again because of the lack of adequate supplies of petroleum derived transportation fuels, particularly in Italy. Development of CNG vehicles on a larger scale did not begin until the 1980s in Europe and Latin America, and in the 1990s in Asia. As of year-end 2011, there were more than 14 million NGVs, mostly CNG vehicles, operating on six continents, representing a global market share of about 2 percent.

The NGV industry is growing rapidly, particularly in North America, where large unconventional gas reserves have boosted production and reduced retail natural gas prices to levels well below conventional fuels. The number of NGVs has doubled since 2006 alone, with around 16,2 million by 2012, with a 23% per year growth rate since 2000. The International Association for Natural Gas Vehicles (IANGV) is projecting an increase to 50 million by 2020, and to 100 million by 2030 with rising gas production globally (see Figure 35). According with the National Gas Vehicular Association (NGVA), the number of NGVs in 2015 would be around 35 million.

Since 2000, NGV adoption is principally in developing countries: the Asia Pacific region is leading its penetration with 5.7 million vehicles (mainly Pakistan, Iran and India) followed by Latin America with 4 million (most of them in Argentina and Brazil). Among European countries, Italy has had the deepest market penetration, and recently NGVs are growing in other countries. At year-end 2011, there were approximately 65 manufacturers producing some 300 models globally.

Figure 37 – IANGV Forecast of Worldwide NGV Growth



Natural gas is used to operate vehicles of all types and classes, although LNG tends to be confined to use in larger vehicles, particularly where storage or weight are a factor, as shown in Table 6. Thus far, CNG is by far the most common form of NGV, especially as lighter vehicles comprise most of the fleet, although LNG use is becoming more popular for heavier vehicles.

Table 19 – Types of NGVs Operating on CNG and LNG

Vehicle Type/Class	CNG	LNG
Automobiles	X	
Motorcycles, scooters	X	
Vans and trucks	X	X
Buses, school buses	X	X
Small marine craft	X	
Ships, tankers		X
Railroad cars		X
Aircraft		X

NGVs have been largely adaptations or, in millions of cases, simply conversions of petroleum fueled vehicles, what have enabled the world's NGV fleet to grow but implies that most of today's NGV conversions and bi-fuel and dual-fuel engines (that run on conventional fuel or natural gas or both) are optimized purely for liquids and are largely sub-optimal in numerous ways, including their engines, fuel system configurations and storage system location and positioning. Even purpose-built natural gas-only engines are offshoots of petroleum technologies that have evolved and been refined and improved for over a century.

However, there has been an important development in recent years and although not long ago gas-only engines had a power limitation of 350 HP, new engines are to 450-500 HP. Technology has been proven and promising developments include:

- High Pressure Direct Injection (HPDI), a technology being developed that injects both diesel and gas at high pressure into the combustion chamber.

- Integrated Storage Systems (ISS), a CNG storage configuration mentioned above that utilizes three lightweight, high-density polyethylene small-diameter cylinders encapsulated within a high-strength fiberglass pod containing impact-resistant foam. Two or three pods may be positioned within the vehicle's crumple zone in locations that do not interfere with trunk space.

There are several drivers for the development of this market:

- <u>Environmental</u>. Natural gas in transport ensures lower levels of emissions than any other fossil fuel:
    - Reduce CO2 emissions and NOx
    - Does not emit sulfur dioxide
    - Does not emit solid particles
    - Contains no lead or heavy metal traces.
    - Lower levels of noise and vibration emission diesel engines.

  As emission limits these limits are becoming more restrictive in several countries, the natural gas-powered vehicles could be made to more easily and will therefore gaining in competitiveness.

- <u>Economical</u>. Until 2005 there was parity between the prices of crude oil and natural gas; however the current spot market prices and market futures show a growing disparity, differential that future could be even more favorable to natural gas given the world's proven reserves of both fuel.

  Fuel savings of 20-40%, being fuel the second largest variable cost of these companies, are able to offset higher initial expenditures, with return investment periods of even three years. It is expected that this initial higher cost, will decrease as technology becomes more standard or demand increases.

NGVs are best suited for fleets of vehicles operating many miles per day. For example, NGV economics succeed in such high mileage fleets as taxis, transit and school buses, airport shuttles, etc. To control costs and facilitate operations, such vehicles are parked, fueled and maintained in centralized facilities.

Apart from the fuel savings, the use of LNG increases engine performance and incurs lower maintenance costs (longer lubricant and spark plugs, filters saving ...)

- Availability and security on supply. Although it is early to say if we have already reached peak oil in terms of global production or not, it is clear the limitation of global reserves and the concentration of the largest reserves in geopolitically complex areas. However, the existence of new reserves of shale gas has broken the classical energy market.
- Regulation. Many governments are giving support to this technology trough tax breaks, grants and/or exemptions. An extension through 2030 of 50% reduction in minimum tax set by the EU for natural gas or an exemption from registration tax for vehicles with emissions <120 gCO2/km, for example.

  On the other hand, "Atmosphere Urban Areas Protected" has been declared, as in the case of Los Angeles Port or the EU, in its Clean Power for Transport Package, is proposing that by 2020 there is an LNG station every 400 km along the European road network.

Although the use of NGV still faces some challenges before their mass production:

- Fuel storage. Natural gas occupies more volume than traditional liquid fuels thus it must be compressed (usually to around 250 bar) or liquefied to make it practical for transport applications. Because of its high energy density, a vehicle fueled by LNG can have a range comparable to that of diesel (1,000 km) with a small increase in weight and volume: 1 liter diesel equivalent to 1,8 liters of LNG while 1liter of diesel equivalent to 5 of CNG.

  CNG or LNG is stored in cylinders, and reduce available space to the extent these are stored in the trunk unless the tanks are small, which reduces acceptable range. This range-versus-space trade-off remains an issue for NGVs even though it has largely been resolved by technologies involving small tank pods positioned strategically aboard the vehicle in a way that enables nearly full use of trunk space while preserving long range performance.

- LNG boil-off. Slightly pressured LNG-based storage systems fit best in fleets of vehicles that keep moving or otherwise keep operating on a consistent basis so that control of boil-off gas does not challenge operations. Examples of LNG-suitable fleets include heavy-duty municipal vehicles, transit buses in frequent service, long-distance highway trucks (if fueling can be arranged, see below), large-scale portable generators, railroads and, of course, cargo ships, especially LNG tankers.

- Limited refueling infrastructure. Fueling facilities are ample, although not necessarily where needed, and may not be sufficient in some especially promising regions for NGVs. Urban and centrally fueled facilities meet fueling needs on a project-by-project basis, i.e., necessary fueling facilities are installed in conjunction with NGV procurement. Especially promising overland truck and railroad markets for LNG require placement of fueling facilities at regular intervals along motorways and autoroutes, a process that was continuing at year-end 2011.

It is expected that with improved technology, research, and infrastructure, the use of NGVs in both fleet and non-fleet settings will increase in the future; fiscal conditions along with the availability of fuelling stations and NGVs, are essential criteria.

Figure 38 – Chart-NexGen LNG Fueling Station in Southern California

World's largest LNG/LCNG station built by Chart-NexGen in California.
4×60.000 liters storage capacity, 6 LNG dispensers and 3 LCNG dispensers. Serving 200 refuse vehicles.

LNG vehicle and fueling projects that were moving forward by year-end 2011 included an especially ambitious plan to develop infrastructure in the U.S. based on central LNG liquefaction facilities of the kind shown in Figure 36. Each LNG plant feeds numerous satellite LNG fueling stations (the so-called Boone Pickens plan). In a program that is partly subsidized by the U.S. and state governments, two central liquefaction-for-vehicles plants have entered service, and dozens of satellite LNG storage and dispensing facilities are in development.

2.6.5. Satellite and Peak Shaving plants

2.6.5.1. Satellite plants

These stations, built to store LNG in a smaller scale than larger tanks, are usually placed at the gas end user or as source for local pipeline network. Storage tanks are sized for a reasonable retention time of three to fourteen days, depending on consumption capacity.

Figure 39 – Satellite Plants

Satellite plants have the following basic systems: Unloading Unit (for LNG tanker trucks); Storage; Regasification; Measurement and send out.

The LNG tank truck discharge is done through the connection of the tank truck to the storage tank in the satellite plant, by means of two piping systems, a fixed one (pipes) and short cryogenic hoses, which are the ones that are connected to the tank truck. The discharge is done by pressurizing the LNG tank truck. To do this, a small amount of LNG is sent to a vaporiser called "of fast pressurisation". The outlet of this vaporiser is sent back to the tank through another cryogenic hose.

The LNG is stored in cryogenic tanks. These cylindrical tanks can be placed either vertically or horizontally and they have two shells: the internal one built in stainless steel and the external one of steel. The space between the vessels is filled with expanded perlite and vacuumed, to reduce the heat exchange with the environment.

The LNG from the storage tanks is sent to the vaporisation unit. A small vaporiser per tank maintains the internal pressure and makes it possible for the plant to feed gas to the distribution network or the end clients associated with the plant. This facility vaporises and heats the LNG to parameters compatible with the distribution network. The unit comprises a series of finned tubes through which the LNG and the vaporised gas is circulated.

There are two kinds of vaporizers: ambient and water bath vaporizers. The first ones do not need any added energy, and the second type can be heated by natural gas or other available fuel. The design and size of the vaporizers are determined to guarantee a pressure, flow and temperature according to the requirements.

A layer of ice and sleet builds up on the vaporisers while in operation, which makes it necessary to periodically disconnect them from the LNG flux and allow for their natural reheating.

A distinct advantage of LNG satellite stations is the flexibility of the flow control rate in the range of 0 to 100% with potential for several hours overload.

There are several kinds of satellite station applications:

- Direct heating and process technology systems ensure continuous gas delivery according to consumption rates with possible seasonal or daily diagram variations. High reliability and several years' uninterrupted operation are typical requirements.
- Back-up systems are incorporated at sensitive process technologies like glass factories, which normally operate on pipelines, but a back up system is needed for any potential pipeline interruption. Storage capacity is sized for coverage of limited time operation needed for failure rectification or for safe shutdown of the plant without damage to equipment or product.
- Peak shaving systems are designed to compensate for deficiencies in gas delivery, when gas delivery by pipeline cannot cover consumption due to limited gas supply, often related to source capacity or pipeline sizing. Typically they are used for additional heating during several very cold winter days.

United States, Spain and Japan are the countries with more satellite plants. Other countries using these facilities are Germany, United Kingdom, Norway, Switzerland, Finland, Australia and Canada.

2.6.5.2. Peak Shaving plants

A Peak Shaving Plant is an installation that allows to store LNG and inject it during the periods of maximum demand.

Figure 40 – Peak Shaving plant

These plants are located strategically near the centers of consumption, and generally distant of the zones of gas production, in places with high seasonal oscillation of the demand (usually domestic and residential consumers).

Having Peak Shaving Plants reduces the necessity to have capacity from the zones of production of gas, and the dimensions of the involved pipeline, that are used in seasonal form. The existence of these plants is an effective alternative to diminish the total cost of that transport from the production to the consumption centers, with high demand in the winter season.

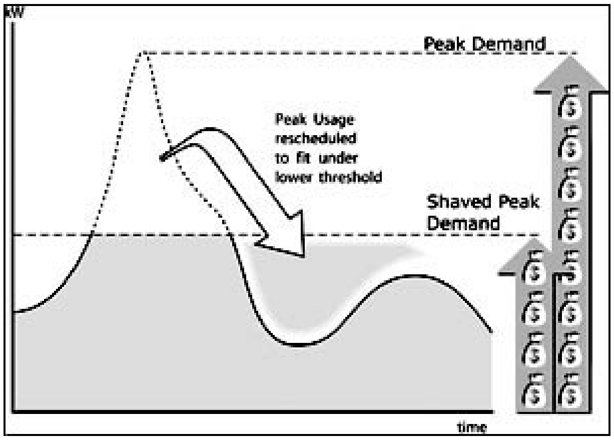
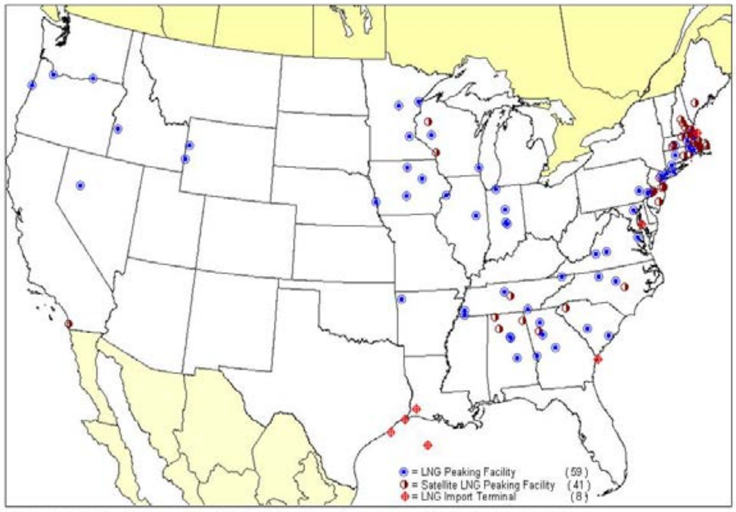


Figure 41 – Savings with Peak Shaving

The use of peaking facilities, as well as underground storage, is essentially a risk-management calculation, known as peak-shaving. The cost of installing these facilities is such that the incremental cost per unit is expensive. However, the cost of a service interruption, as well as the cost to an industrial customer in lost production, may be much higher. In the case of underground storage, a suitable site may not be locally available. The only other alternative might be to build or reserve the needed additional capacity on the pipeline network. Each alternative entails a cost.

There are 79 Peak Shaving Plants in the world, 62 in North America, 8 in Europe, 8 in the region Asia-Pacific and only one in South America (Argentina).

Figure 42 – Satellite Plants and Peak Shaving in the US



Note: Satellite LNG facilities have no liquefaction facilities. All supplies are transported to the site via tanker truck.
Source: Energy Information Administration, Office of Oil & Gas, Natural Gas Division Gas, Gas Transportation Information System, December 2008.

3. Economics and Commercial Aspects of the LNG Value Chain

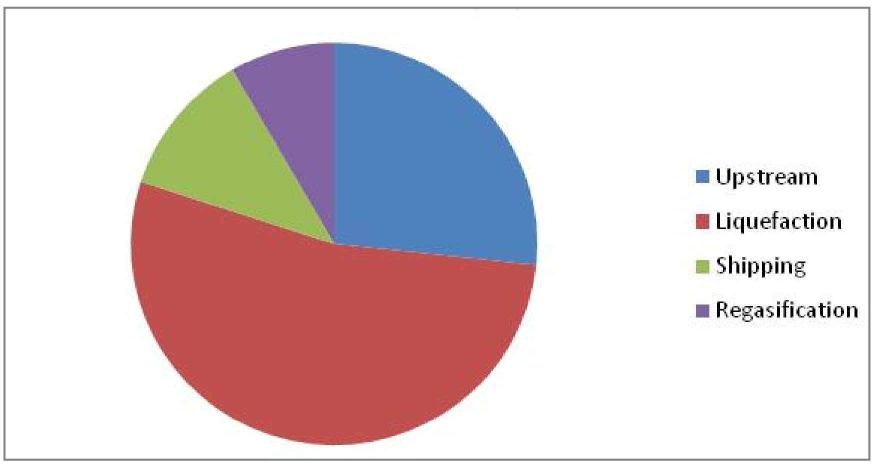
Economics and commercial aspects of the LNG value chain are described in this section. The major elements of this review are as follows:

- Changing capital and investment requirements
- Structure of LNG business and investment models
- Risks and risk allocation along the value chain
- Contracting and commercial mechanisms in the industry
- Competition between LNG and pipeline gas.

3.1 Capital Investment Requirements

By far the major capex component, liquefaction represents more than half of the total investment in the LNG value chain facilities (see Figure 43). Upstream projects bear higher levels of risk and uncertainty, but also have compensating rates of return.

Figure 43 – Distribution of Capex in a LNG Chain (%)



The typical range of investment required and costs in a major integrated LNG project are as shown in Table 20:

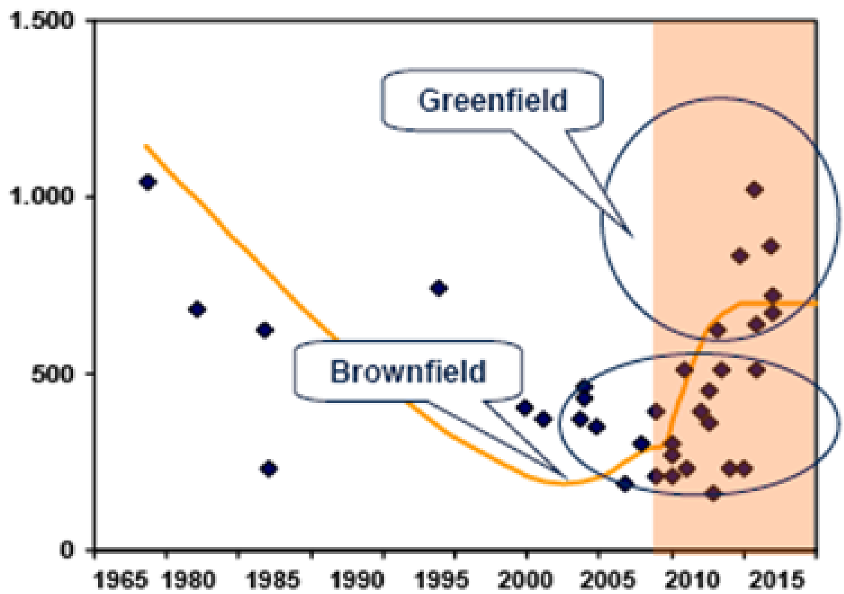
Table 20 – Range of Typical Capex for a 10 mtpa LNG train

	Upstream	Liquefaction	Shipping	Regasification	TOTAL
Gas Use (%)		10-14%	1.5-3%	1-2%	12.5-19.5%
CAPEX ($/tpa)	250-750	750-1250	125-300	125-200	1250-2500
Cost ($/MBTU)	1-3	3-4.5	0.8-1.5	0.4-0.8	5.2-9.8

For an extended period of time, design improvements in liquefaction plants and tankers had the effect of reducing costs. As recently as 2003, it was common to assume that this was a "learning curve" effect and would continue into the future, although perhaps at a diminishing rate over time. But this perception of steadily falling costs for LNG has been dashed in the last several years.

With exceptional increases in demand, including to meet potential North American demand, the construction cost of green-field LNG projects started to skyrocket from 2004 afterward and rose from about $400 per ton of capacity to $1.000 per ton of capacity in 2008. Figure 44 vividly demonstrates this point.

Figure 44 – Costs of Representative Greenfield and Brownfield LNG Projects over Time



The main reasons for skyrocketed costs in LNG industry can be described as follows;

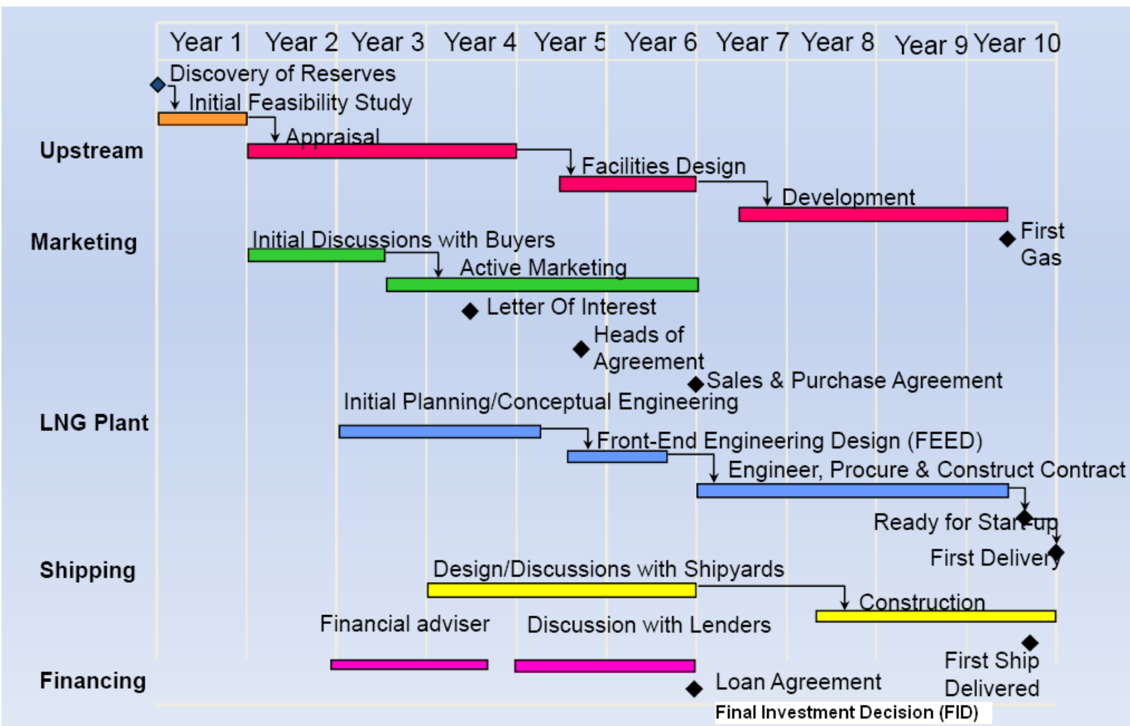
- Low availability of EPC contractors as result of extraordinary high level of ongoing petroleum projects worldwide.
- High raw material prices as result of surge in demand for raw materials.
- Lack of skilled and experienced workforce in LNG industry.

Since 2008, the global financial recession appears to have reduced the rate of increase in the rate of increase in construction costs of LNG plants, although the extent of this decline, if any, remains unclear.

The development of bidirectional projects (liquefaction added to an already operational regasification terminal) in the Gulf of Mexico has come with lower construction costs than a greenfield liquefaction project because of the common facilities and infrastructure elements previously built, including LNG storage tanks, berthing facilities, pipeline connections, etc.

Developing an integrated LNG project typically takes about a decade, including feasibility studies, permitting, shareholders agreements, engineering, construction, marketing agreements, feed gas supply contracts, financing issues, shipping arrangements, and on to construction and installation (see Figure 45).

Figure 45 – Illustrative LNG Project Schedule



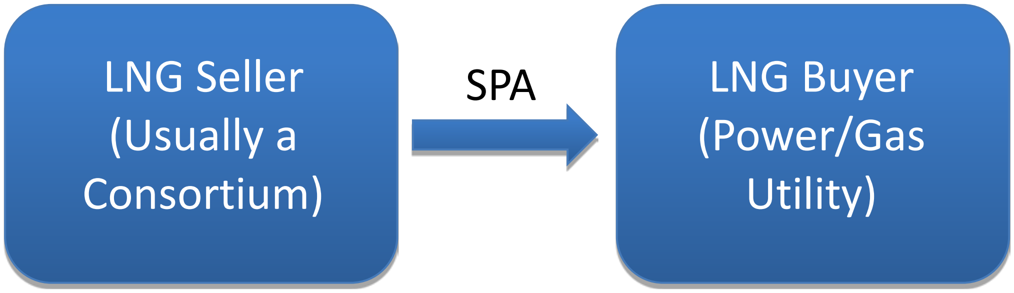
3.2 LNG Business Model Structures

The LNG development and commercial space has gone through an evolution from the simple bilateral buyer-seller transaction toward a set of more complex, diverse and highly structured arrangements involving a wider set of parties to transaction. The following discussion traces this evolution and defines the parties.

3.2.1 Traditional Structure

Under the basic, traditional deal structure, a selling consortium goes to contract with one or more gas consuming energy utilities, as depicted in Figure 46 below:

Figure 46 – Traditional Bilateral LNG Parties and Transaction



The parties to this transaction are as follows:

- The seller, usually a consortium consisting of national oil companies (NOC) and investor-owned companies (IOC), is responsible of developing feed gas production, arranging for delivery of feed gas to the liquefaction plant, and development and operation of the liquefaction plant. The LNG seller is typically the owner of the liquefaction plant and may also own (or own development rights to) the feed gas, see below.

- The buyer, usually an energy utility, is responsible of developing the downstream market and normally owns and operates the receiving regasification terminal.

Depending upon whether the sale is FOB or DES – respectively, LNG ownership transfers at the liquefaction plant's point of delivery aboard ship (Free on Board), or at the receiving terminal dock – the shipping is controlled by the buyer or the seller, respectively.

This is a simple and consistent model, where the roles of the parties are clear and the risks are shared between the seller and the buyer. This is very adequate for long-term SPA contracts as reserves are dedicated to the project and deliveries can be programmed in advance, which is very useful for financing the project. However this is not the most appropriate model for short term trading because it is not set up to respond in an agile way to changing market conditions.

3.2.2 Integrated Project

In an "Integrated Project" the shareholdings in the company that develops the gas field are the same as the shareholdings in the company that owns the liquefaction facility and downstream facilities as well. The Project controls all the links in the LNG chain: gas supply, liquefaction plant, shipping, regasification terminal and downstream marketing. The main advantage is that the interests of the shareholders are aligned and it is a very useful model for diversification and risk management, but it requires additional capital invested because capital must be raised to finance the entire LNG chain, rather than pieces of it.

Currently, the trend in the market is toward vertical integration both for producer integrating downstream and for utilities integrating upstream. Market conditions and commodity prices may suggest one formulation of the other:

- In a low-priced market environment, the value flows downstream and thereby enables relatively greater investment on the part of the buying utility in upstream segments of the LNG chain.

- In a high-priced market environment, the value flows upstream, thus enabling the opposite, i.e., the selling entity has greater wherewithal to become the integrator.

The Qatargas II project is an excellent example of a vertically integrated LNG chain ownership structure; in this case, the upstream consortium Qatar Petroleum-ExxonMobil controls each of the links in the LNG value chain.

Other examples of sellers integrating downstream and buyers integrating upstream are shown in Table 21:

Table 21 – Examples of Vertically Integrated LNG Chain Ownership Arrangements

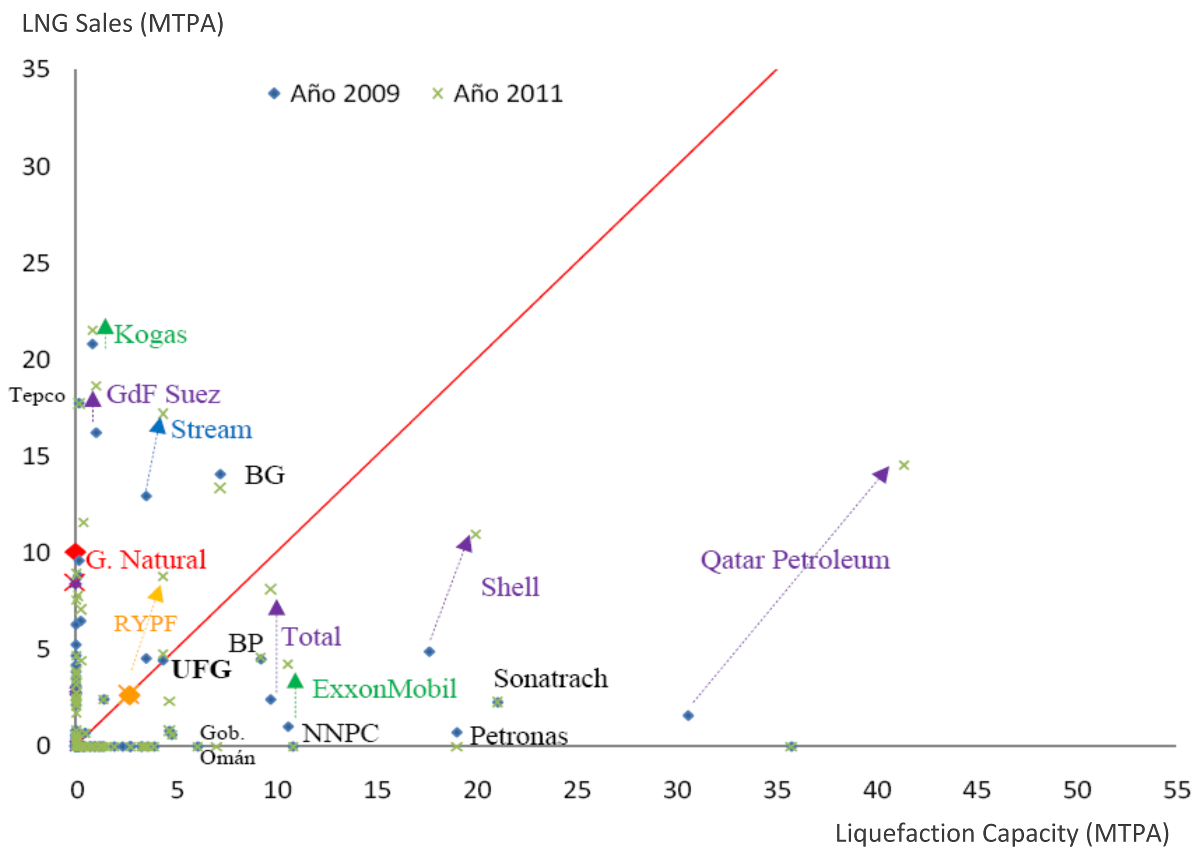
KOGAS Consortium	➢ 5% in Rasgas ➢ 5% in Oman LNG ➢ 6% in Yemen
Unión Fenosa Gas	➢ 80% in Damietta ➢ 7,36% in Qalhat
GDF-Suez	➢ 5% in Egyptian LNG, train 1 ➢ 12% in Snohvit ➢ 10% in Atlantic LNG, train 1
TEPCO & Tokyo Gas	➢ 9,2% in Darwin ➢ 5% in Pluto

	US	UK	NW Europe	Other
Sonatrach (*)	Cameron and Cove Point (capacity holder)	Isle of Grain (capacity holder)	Montoir (France, capacity holder)	Reganosa (10%)
Qatar Petroleum	Golden Pass (70%)	South Hook (68%)	Zeebrugge (Belgium, capacity holder)	Adriatic LNG (Italy, 45%)
Petronas		Dragon (30%)		

(*) Sonatrach has also established local marketing affiliates in several markets, including Spain, Italy, UK and US.

By nature of their ownership profiles, integrated LNG projects have an inherent incentive to maximize capacity utilization. Figure 47 illustrates this effect for a number of vertically integrated projects – in many cases, LNG sales during 2009-2011 increased to a greater extent than liquefaction capacity, e.g., see nearly vertical arrows representing Stream and Shell in the figure.

Figure 47 – Examples of Firms Moving Toward LNG Chain Vertical Integration in 2009-2010



3.2.3 Role of the Aggregator

An aggregator in the LNG chain is an entity who holds a portfolio of LNG supply sources and downstream markets, and is able to optimise supply and demand on its own (or chartered) fleet of LNG carriers. This highly flexible model is appropriate for short-term trading.

As an example, BG conforms to the aggregator model:

- Portfolio of supply sources: Egypt, Trinidad and Tobago, Equatorial Guinea, Australia.

- Portfolio of downstream markets: United Kingdom (Dragon LNG), United States (Lake Charles and Elba Island), Italy (Brindisi), Chile (Quintero), Singapore.

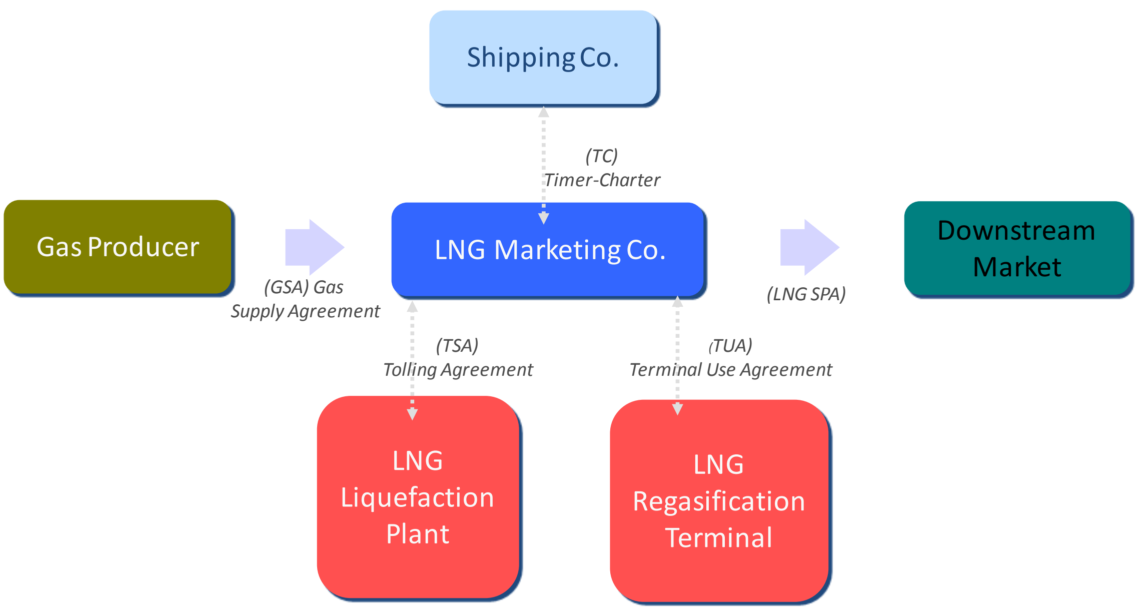
This model is being followed by most major global energy firms involved in LNG.

3.2.4 The Tolling Model

This is largely a capacity leasing contract model. Typically, the toller enters into a contract with the infrastructure owner under which a fixed charge is paid to use capacity within the liquefaction and/or regasification facilities. Tolling provides a way for the infrastructure owner to recover his investment and avoid commodity risk. The latter advantage accrues because the LNG plant does not take title to the commodity (LNG) and, consequently, avoids risks arising out of LNG price movements, gas supply and marketing.

A schema of this structure in illustrated in Figure 48:

Figure 48 – Tolling Structure



3.2.5 LNG SPA Contracts

The Sale and Purchase Agreement (SPA) is the central element of the LNG value chain, and it could be for a short term (spot) contract or for a long term agreement.

The first gas SPAs were agreed between Canada and the United States for long term pipeline sales.

Many of the key terms in a SPA contract are becoming standardized. However, the differences between markets and projects still require negotiation and modification of some clauses.

The main typical clauses are:

- Quantities:
    - Annual Contract Quantity (ACQ): the volume to be purchased every year by the buyer. If the SPA is associated to a LNG project, it usually has a build up period in order to allow the producer to reach the maximum operation level.
    - Take or Pay (ToP): the amount of gas that should be taken or paid by the buyer. It usually has some flexibilities:
        - Downward Quantity Tolerance (DQT): small volume that the buyer can request to reduce the ACQ without entering into ToP.
        - Make up volumes: volumes that the buyer can request and receive within a period of time because they were already paid under a ToP provision. The price adjustment for these volumes should be included in the SPA contract.
    - Round up and down: volumes designed to reflect the fact that the LNG facility may not be able to deliver precise volumes over the course of the year.
    - Excess quantities: additional volumes that could be produced by the facility.
- Conditions Precedent or conditions that should be satisfied before the deal becomes binding. It provides protection for both parties.
- Quality specifications
- Scheduling, becoming more important with the development of LNG trading.
- Measurement, including volume in energy units and composition.
- Transfer of Title: FOB (Free on Board) or DES (Delivery Ex-Ship).
- Destinations clauses
- Price, usually a formula linked to energy markets. It could include other conditions like:
    - Price reviews or reopeners,
    - Change of circumstances,
    - Profit sharing mechanisms in the case cargo diversions,
    - Most favoured customer, etc.
- Force Majeure: provisions designed to excuse the parties from performance of their contractual obligations in circumstances beyond their control.
- Liabilities and liquidated damages: the amounts to be paid are agreed in advance.
- Other contractual clauses as confidentiality, billing, cession, governing law and dispute resolution, etc.

Before signing an SPA contract, usually the parties agree less complex documents as a Memorandum of Understanding (MoU), Term Sheet, Letter of Intend (LoI) or Heads of Agreement (HoA) outlining the main terms and conditions of the potential agreement. These previous documents can be binding or non-binding.

3.3 Risk Analysis and Allocation

This section reviews and discusses the risks, insurance mechanisms and allocation processes specific to integrated LNG Projects. This discussion lays a basis for understanding financing costs of LNG projects.

3.3.1 Catalogue of LNG Project Risks – Pre-Completion

Risks fall into two basically separate periods of time in the life of an LNG project – prior to start up of the project (Pre-Completion) and following in-service, i.e., after the project starts its commercial operations (Post-Completion).

3.3.1.1 Catalogue of LNG Project Risks – Pre-Completion

During the preliminary phases of the project and the construction phase, the main risks are:

- Permitting. The risk that the project fails to receive all the necessary approvals before start-up of construction, or that any approval is withdrawn or cancelled during construction.

- Cost overruns. The risk that the project's construction costs will exceed the budgeted amount. Projects may be developed under a single lump sum EPC contract, which tends to be preferred by potential lenders, although to succeed under this structure, the EPC Contractor needs to have both the ability and the incentive to ensure project completion in a smooth and timely manner. Such EPC contracts mitigate construction risks, but they include a premium charged to the total costs. The characteristics of the EPC Contract usually include:

    - Lump sum turnkey contract with single point of responsibility residing with the EPC Contractor
    - Partial indexation of the costs: manpower, steel, equipment
    - Liquidated damages for performance, which are sized to compensate in part for the loss of profit arising from the failure to meet process performance guarantees
    - Liquidated damages for delay, sized in particular to meet commercial commitments.

    The EPC contract needs to afford clear visibility over the contractual responsibilities, the costs of the various procurements as well as the construction schedule towards the completion date, with benchmarks and failure penalties.

- Upstream. The risk that the upstream gas project segment fails to deliver gas on time or in sufficient quality or quantity. In order to minimize the upstream risk for the partners, the upstream development needs to be reviewed by third parties:

  - An independent reserves consultant to evaluate the Proved (or P90) gas reserves dedicated to the supply of the Project
  - Independent technical consultancy on the adequacy of the upstream facilities for the supply of sufficient volumes of gas with required specifications to the Project, and on the proposed development budget, schedule, and contracting, including production and delivery (pipeline) components
  - An independent downstream technical consultant may opine on other issues such as provision of utilities and services, etc.

- <u>Design/performance failure</u>. The risk that the project fails to meet the design criteria. This risk may be minimized by relying upon proven technology with only minor improvements confined to specific, identified areas. Reliance upon experienced EPC contractors will also minimize performance risks.

- <u>Schedule/delay</u>. The risk that the project start-up will suffer delay. Start-up delays may result in increased project costs, failure to meet timely financial commitments, and breach of contract with LNG consumers. Project schedule delays are typically covered by liquidated damages under which the EPC contractor must compensate the project for costs of delay; however, such amounts are often insufficient to cover all schedule/delay risks. Risks of delay may also arise for reasons other than can be attributed to the EPC Contractor. The successful completion and operation of the Project will depend critically on all the elements of the operations chain. All the elements must be completed and ready for operation at the same time:

  - The upstream wells and pipelines up to the processing plant, intended to supply gas
  - The processing plants
  - Any utilities outside the scope of the Project
  - The liquefaction Unit
  - The loading port
  - Shipping
  - Regasification facilities
  - Pipelines to the markets
  - End user facilities: CCGT's, petrochemical complex, power generation units.

  The partners of the project can develop a contracting strategy that will minimize the risks; an option is to transfer part of the risks to third parties.

- <u>Pre-completion shipping risk</u>. The risk that the project fails to contract sufficient or timely shipping capacity. An alternative approach would involve an off-taker managing its own portfolio of LNG vessels, to allow it to optimize its fleet across its global LNG shipping operations, but this off-taker has to be capable of providing ships at completion. Given the uncertainty of the LNG final market, it is currently difficult to foresee what the requirements would be of the LNG end buyers in terms of involvement in the shipping structure. Indeed, some buying countries have in the past established requirements in terms of ship flag or involvement of the local shipyard industry / ship owning business. Such requirements would need to be accommodated and/or mitigated in the shipping structure.

- Political and country risk. The set of risks related to political delays, strikes, failure to uphold country-based contracts, permits and agreements, violence, expropriation, final permits, non-transfer, and others. An appropriate degree of political risk protection for the project could be necessary in those countries with higher political risk.

3.3.1.2 Catalogue of LNG Project Risks – Post-Completion

Post-Completion risks include:

- Feed gas supply. Usually the integrated LNG projects are based on the assignment of a dedicated field/area to the project with enough proven reserves to cover the feed gas supply in the long term. One option to mitigate the reserves risk is a back up supply, the partners could require at the time of the Project Completion an updated reserves estimate to provide assurance of availability of reserves to meet the contracted volumes.

  The studies are based on the P90 reserves certified in some cases by an independent reserves consultant, and, while ideally those should be sufficient over the life of the Project. The analysis is based on reserves and reservoir performance technical issues, its needed to perform several sensitivities taking into account the impact of current, planned and future possible developments on the field performance.

  The alignment of interest of the NOC (National Oil Company) and the IOC International Oil Company) through the continuing involvement in the operations and maintenance of the Upstream Development is a strong mitigating factor.

- Upstream Operational Risk. Considering the importance of a reliable and quality-constant gas supply to the Project, the continuity of involvement of the partners in the Upstream through construction to operations is paramount for the project development. Sharing knowledge and expertise from similar fields already in operation is a way to reduce operational risk.

- LNG off-take. The LNG industry has constantly relied to date on strong take-or-pay off-take agreements for LNG sales with end users (such as gas or power utilities). The LNG off-take risk has three main elements: market risk, price risk and credit risk.

Partners of the Project will fix the following key requirements:

- o Sell a minimum quantity through take or pay contracts.
- o Contract with a satisfactory counter-party (buyer): the off-take agreements need to have a tenor at least as long as the tenor of the debt and to involve a competent and creditworthy company with experience in the market and with a clear ability, incentive and obligation to ensure successful marketing – to the extent there would be a pass through to JV Co of the End- user SPA risks, Lenders will require a guarantee or credit enhancement of the underlying obligors if not deemed creditworthy;
- o Focus on the interplay between the LNG Intermediary SPAs and the End-user SPAs.
- o Volume Risk usually is borne by the Off-takers either through take-or-pay obligations or other mechanisms.
- o Price Risk FOB LNG prices are usually indexed to Brent or oil products. Partners generally accept price risk to the extent that the price basis is transparent and is based on a well recognised index, and that they can be made comfortable that the Project will resist low price scenarios
- o Credit Risk of the buyers. The more risks are passed through between the LNG end-users and the Project through "transparent" Intermediary LNG Off-takers, the more important is the credit quality of the end-users
- o Environmental and Permitting Risk. The main environmental issues raised by the Project comprise:
  - ▪ Emissions
  - ▪ Cooling water
  - ▪ Relocation and population issues
  - ▪ Sulphur production
  - ▪ Management of hazardous and toxic materials and waste.
  - ▪ Clean site, an Environmental Assessment of the site is usually a necessary condition, which could confirm if the plant site is free from environmental contamination.

- Other risk. Volume risk, Price volatility, Operational risk, Force majeure, Environmental risk, Financial risk (forex, interest rate etc.) or Political risks.

3.3.2 Insurance

Partners have focused more on insurance aspects of the project over the recent years in order to reduce the exposure and risks.

3.3.2.1 Insurance Cover during the Construction Period

Business practice is to secure insurance cover for Construction All Risks for the maximum capacity available in the construction insurance market, up to full reinstatement value.

That includes:

- Construction erection risks - usually is expected to include construction delay in start up insurance to cover consequential loss (and provide protection for fixed operating costs and debt service of the Project).
- Transportation insurance, usually includes marine cargo delay in start up.
- Third party liability.
- Sabotage and terrorism, which used to be part of the construction all risks policy but is now commonly the object of a stand-alone policy due to restricted availability.

The Construction All Risks insurance will be expected to cover the following:

- All physical loss or damage to the Project, arising out of the performance of the Project and comprising all permanent and temporary work, and applying on the Project site and in transit.
- Protection against all natural force majeure exposures including earthquake and seismic activity, windstorms, etc.
- When a project is developed under a single EPC contract, the Construction All Risks insurance is sometimes placed by / under the responsibility of the EPC Contractor. It is then key to ensure that the EPC Contract includes key requirements in terms of insurance and for the Partners to monitor the process, to avoid renegotiation with the EPC Contractor at a later stage, or for the Partners or the Project to have to enter into additional insurance layers.

Partners should seek subjecting the insurance obligations to available market capacity at reasonable cost investigations on what would be available in the insurance market for the Project. Prospects in the market should be initiated early enough, as it will have implications on the Project risk allocation. In particular, work on the assessment of the Estimated Maximum Loss will need to be undertaken by the Sponsors long before beginning the insurance due diligence.

3.3.2.2 Insurance Cover during the Operation Period

As regards the operation period, following Project Completion, insurance is generally not available at the time of financial closing, and is usually required that by financial closing insurance requirements for the operation period are clearly identified and agreed upon, and cover availability thoroughly assessed.

The insurance programme during the operation period will include:

- Property damage all risks insurance, on a full reinstatement basis, including protection against all natural force majeure exposures.
- Business interruption insurance, covering at least debt service and operation and maintenance expenses for an indemnity period to be defined, but in the order of 18-24 months (this will have to be consistent with the estimated maximum loss).
- Third party liability - information regarding neighbouring industries will be required for the establishment of the insurance policy.

3.3.3 Risk Allocation

The previous sections have highlighted the project risks and how some of those risks can be partially mitigated. However, even with the various insurances, significant pre-completion risks will remain.

3.3.3.1 Partners' Completion Guarantees

Potential lenders are usually reluctant to accept material risk prior to completion of a project and there are precedents for partners to provide guarantees of debt prior to completion for LNG projects, given the extent of completion.

3.3.3. Completion Tests for Release of Sponsors' Completion Guarantees

It is likely to be requested that the completion tests under the EPC Contract evidence that the guaranteed performance under that contract has been achieved (performance testing).

The Sponsors will need to issue completion guarantees, which they wish to issue on a several basis, pro-rata to their shareholding in the Project.

The constructed facilities will need to demonstrate the ability to operate (in connection with the gas feed and any integrated utilities) in the long run in a safe and reliable manner (reliability test). The lenders' tests financial completion are different from the completion tests included in the EPC Contract and their definition is negotiated by the parties.

There are summarised below the main elements of completion test for the release of Partner's completion guarantees

- LNG Plant
    - Acceptance under single lumpsum EPC Contract No material claims outstanding Each EPC performance tests completed All Project costs paid (or in escrow)
    - All material permits received Extended overall performance test

- Upstream Development
    - Updated reserves report
    - Completion of production and processing facilities
    - Performance test All material permits received
- Shipping Updated shipping consultant report [x] cargoes delivered during a defined test period Receiving Facilities

Completion tests in the LNG industry, comprise several items:

- Mechanical tests, such as performance and reliability tests. Those tests usually include more items than a completion test for the final acceptance under the EPC Contract, such as more extended reliability tests for instance. A reliability test included in the definition of financial completion usually consists in the plant running at an average of 85% to 95% of the rated capacity during 90 consecutive days with maximum levels of consumables and minimum levels of production. Such reliability test is tailored to the specifics of the plant.

  The mechanical tests part of the completion tests to be met for the releasing of the Partners' completion guarantees will include performance and related tests on supporting units outside the scope of the Project but on which the Project relies for its operations. When there are several trains, individual reliability tests are imposed in addition to each train (for both the LNG and the Upstream facilities).

- Financial tests may be part of the definition of completion tests for a particular project. Those will include reserve accounts to be fully funded, and may also require some financial covenants being met. There has been a trend in the financing markets for oil, gas and petrochemical projects, for a relaxation of completion tests, noticeably on financial covenants.

  Financial tests are based on confirmed production volumes and consumables, and may be based on either original price projections, or updated price projections. When lenders are required and capable to take product price risk, as would be the case for the Project, a strong case should be made for the financial tests to be computed based on the original price projections set at financial close (i.e. on the original oil price scenario if the LNG price formula is indexed on oil price).

- Commercial Tests. LNG projects also include commercial tests, to demonstrate that all the shipping and receiving facilities, as well as administrative support systems are in place and operating adequately.

  Considering the capital intensive nature of the whole LNG chain, and the requirement for specific infrastructure for shipping, unloading, storage and regasification, tests also include a number of shipments (examples vary between 3 and 14), e.g. a certain volume of LNG have been delivered to the off-taker over a determined period (and in some definitions have been regasified), and revenues have been paid in the cash flow waterfall, to evidence satisfactory completion of the shipping and receiving units.

- Miscellaneous. As part of the completion tests definition, the Project must have obtained all its permits and licences, etc. This is likely to be also required for the Upstream Development.

While the Partners corporate risk and completion guarantees would be accepted by the lenders, it is likely that the NOC does not have an extensive track record in the international financing markets. To make NOC's completion guarantee acceptable to Lenders without a government guarantee, different routes should be explored, in addition to the mitigation of completion risks in the overall project so that lenders' appreciation of the risk of drawing under the Partners' completion guarantee remains remote:

- Disclosure of audited information on the NOC financials and provision of detailed business and financial projections.

- Credit enhancement by the NOOC of its completion guarantee through assignment of export off-take contracts and availability of such export off-take contracts by the time the Project would seek financing in the markets.

Generally, the more risks are allocated to the NOC in the overall risk allocation of the Project, both pre-and post-completion, the likelier a strong enhancement of the NOC credit would be required.

3.3.4. Technology Risk

If the specific technology of the Project, compared to other LNG projects is innovative compared with the more conventional technology might put a greater onus on the Partners' completion arrangements than is usually the case. If such arguments were not strongly refuted, this may prove an impediment for the raising of project financing

Lenders should be able to get comfortable with such risk, if advised by their independent technical consultant that this is a mere extension of existing technology and does not pose unduly additional completion and operation risk to the Project, and is unlikely to cause higher cost overruns. Cooperation between the Partners and the Lenders' independent technical consultant will be key in achieving this. A second condition for Lenders not imposing more stringent completion requirements than for other LNG projects is the level of support which will be provided by the licensor of such technology

3.3.4. Marketing Structure and Mandatory Provisioning

The characteristics of the host country could have an incidence on the structuring of the marketing arrangements. Banks are obliged to make provisions for loans to projects located in "risky" countries which generally makes such lending uneconomic, banks generally do not have to make provisions for loans with the following characteristics:

- Strategic nature of the product for the producing country; Strong off-takers located in non provisionable countries;
- Assignment to lenders of the proceeds linked to the commercial agreement between the borrower and the off-takers in offshore escrow accounts, and
- Sufficient debt service cover and loan life cover ratios. This raises the following considerations:
  - For sales of LNG to End-users located in "risky countries" it will be important that the Off-taker acts as a principal rather than an agent (as is currently considered), to avoid the need to provision, which materially negatively impact both capacity of uncovered debt for the Project and its pricing.

  - Within that provisioning framework, there is some flexibility, as the actual provisioning treatment by a bank for each transaction derive from general structure recommendations made by each central bank authority and its interpretation by each bank.

Lenders will assess the counterparty risk of off-takers acting as principal. The IOC off-takers counterparty risk would not require to be backed by parent guarantees to the extent such off-takers would be existing marketing companies with a substantial position in the markets, and not special purpose vehicles established for the Project. To that effect trading subsidiaries could be acceptable to lenders, subject to disclosure of sufficient information

In most of the LNG projects financed to date, the LNG buyers have absorbed the market volume (and end user credit) risk by undertaking to pay for committed volumes that they have failed to take at the prevailing formula price – so called "take or pay" provisions. In a number of projects, there have also been price floors (or "S curves") that have insulated the lenders from exposure at very low oil prices.

Market due diligence is carried out for all the principal LNG markets under consideration;

Force Majeure terms should be drafted to ensure that there is no pass-through of the end user credit exposure.

The price review mechanism will have to be agreed (as the price is assumed to include elements to cover credit risk, shipping etc in addition to the end market price).

3.3.5. Ways to mitigate the risk

- Long term contacts with fixed volumes and prices for the whole life of the project.
- Tolling agreements
- Force majeure provisions
- Feasibility studies
- Turnkey EPC contracts
- Performance bonds
- Insurance
- Experienced partners and sponsors
- Proven technology