LNG Supply Options

Report for Comisión de Regulación de Energía y Gas, CREG

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Contents

1. Background

Comisión de Regulación de Energía y Gas (CREG) commissioned David Ledesma - South-Court Ltd on 1st March 2011 to carry out a study to examine the potential for imports of LNG into the country. The study is to examine the infrastructure requirements, possible commercial structures for the infrastructure required for LNG imports and purchasing of LNG during the period of El Niño.

As per the contract between CREG and South Court dated 1st March 2011, a scope of work was agreed as set out in Attachment 2. This report covers tasks 1 & 2, namely:

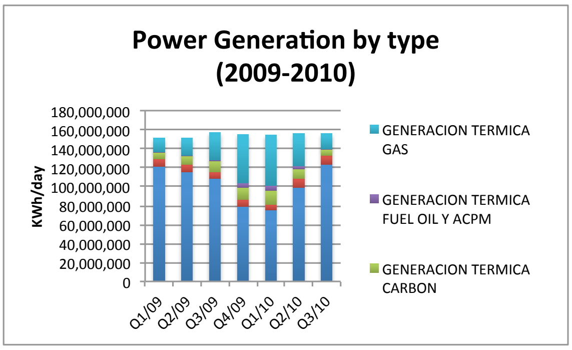
Task 1. To present alternative schemes to obtain LNG to support supply of gas to thermal power plants and to identity the advantages and disadvantages of each of the proposed technologies.

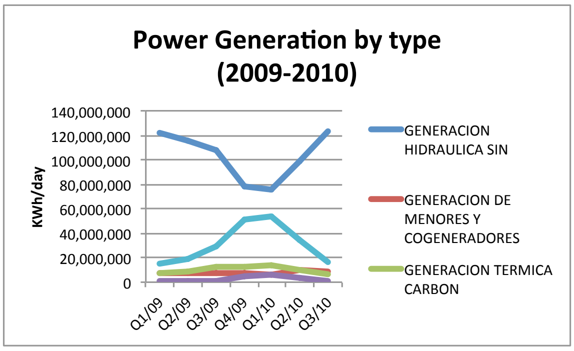
Task 2. To design alternative of business schemes for the development of facilities that were studied in task 1 (such facilities should be constructed by private investors). Each proposed design should be specific about the role and task to be developed by each participant in the proposed structure. It should identify the advantages and disadvantages of each of the proposed alternatives.

2. Why does Colombia need LNG?

Colombia produces ~1090 GBtu/day gas (~ 1.09 bcf/day) and consumes 830 GBtu/day (~0.83 bcf/day) domestically and exports 250 GBtu/day (~ 0.25 bcf/day) to Venezuela. The system therefore, is seemingly balanced.

Power is produced by various sources and during the period Q1/09 to Q4/10 hydro generation represented 67% power produced, thermal (from gas) 20% and coal/oil/other 13%. These percentages, however, include the period Q4/09-Q1/10 when El Niño was active. If this period is taken out of the data it shows a truer picture of power generation in Colombia with 74% power produced from hydro, thermal (from gas) 15% and coal/oil/other 11%. The graph below shows power generation by type during this period.





Source: Data from CREG, South-Court Analysis. See Attachment 2 for data.

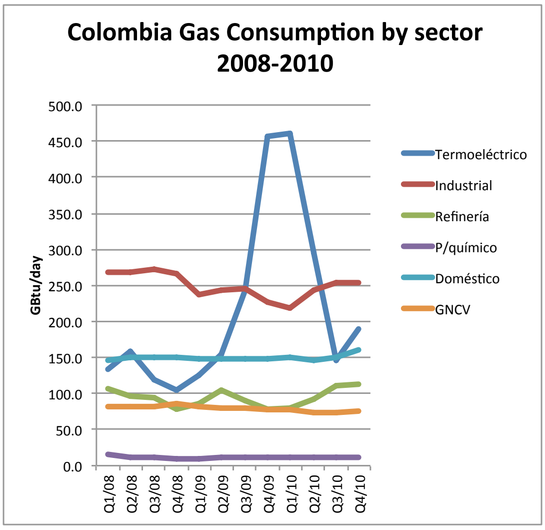
During the period of El Niño (see Attachment 5 which shows the periods of El Niño activity from 1950-2010), Colombia experiences low rainfall usually during the five month period December to April, and maybe longer – 1980-89: the effect of El Niño lasted 14-19 months; 1990-99: 13-15 months and in 2000-2010: for 11 months. During these periods there were severe droughts and, therefore, power from hydro reduces substantially and power has to be generated from other sources. During the period Q4/09-Q1/10 the percentages of power produced from different sources changed to 50% hydro, thermal (from gas) 34% and coal/oil/other 16%. The El Niño effect, therefore, results in a substantial increase in gas demand for power, as well as other sectors, and has lead to diversion of gas from industry to power with resultant shortages of gas for power.

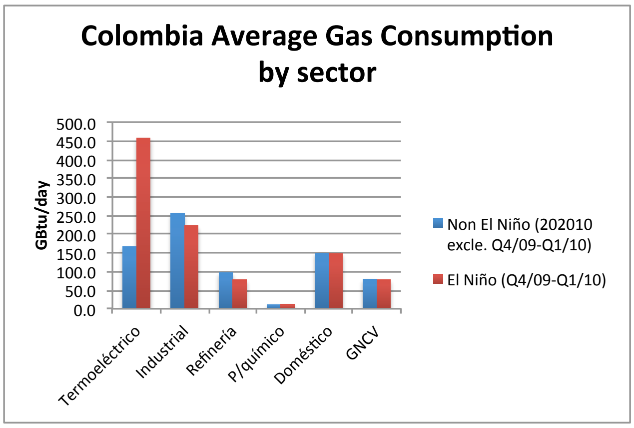
Period	Power from Hydro	Power from Gas	Power from coal/oil/other
Q1/09-Q3/10	67%	20%	13%
Q1/09-Q3/10 EXCL Q4/09 & Q1/10 the period of El Niño	74%	15%	11%
Q4/09-Q1/10 - the period of El Niño	50%	34%	16%

Source: Data from CREG, South-Court Analysis. See Attachment 2 for data.

The occurrence of El Niño cannot be predicted well in advance of the event, on average it occurs every five years, but this can vary from three to seven years.

The challenge is to ensure a balanced gas supply when El Niño is occurring. Power produced from gas increases from 22,566,000 KWh/day to 52,487,000 KWh/day[1]. Gas demand for production of power, therefore, rises during periods El Niño as set out in the graphs below.





Source: Data from CNO Gas, CREG, South-Court Analysis. See Attachment 2 for data.

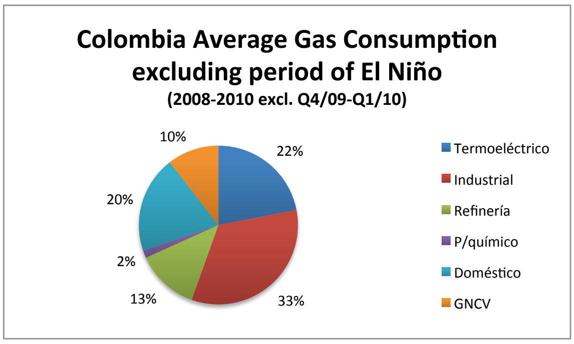
Using data from 2008-2010[2], taking Q4/09 & Q1/10 as the period of El Niño, gas supply to power during El Niño increased from an average of 167 Gbtu/day to 459 Gbtu/day, or 170 million Scf/day to 460 million Scf/day[3](rounded).

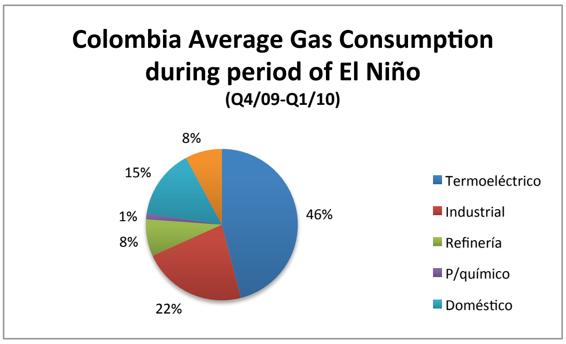
	Normal	El Niño	
(Gbtu/day)	Excl Q4/09 & Q1/10	Q4/09 & Q1/10	Difference
Termoeléctrico	167	459	292
Industrial	255	223	-32
Refinería	97	79	-18
P/químico	12	12	0
Doméstico	150	148	-2
GNCV	80	78	-2
TOTAL	761	999	238

Source: Data from CNO Gas, CREG, South-Court Analysis. See Attachment 2 for data.

In percentage terms, gas consumption for power production rises from 22% to 46% during El Niño.

[1] Period of El Niño is Q4/09-Q1/10. Period of non- El Niño is Q1/09-Q3/10 excluding the El Niño period
[2] Different period used for gas vs. power due to data available.
[3] For the purposes of this document it is assumed that 1 Gbtu/day = 1 million scf/day gas, rounded

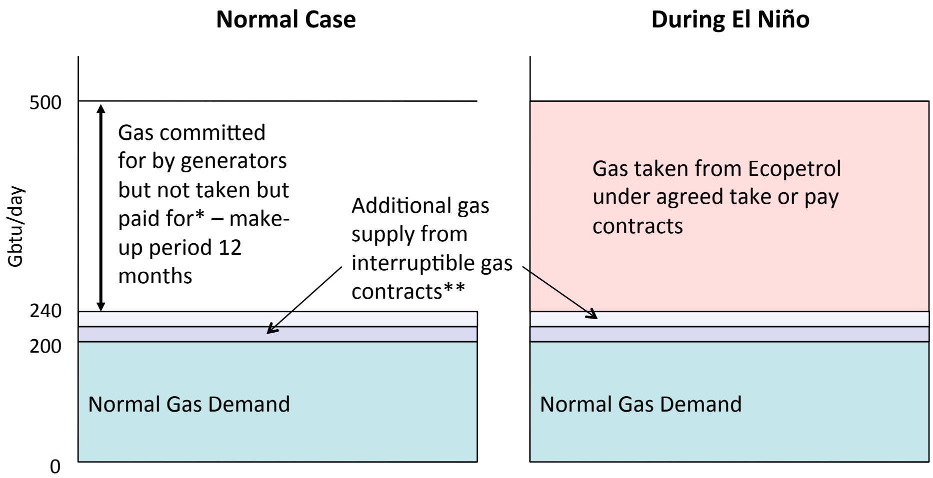




Source: Data from CNO Gas, CREG, South-Court Analysis. See attachment 2 for data.

Gas demand can therefore rise from ~300 scf/day during El Niño. Based on these regular occurrences, it is assumed that El Niño may return during the winter of 2014/15 and the country must be prepared for this occurrence.

It is the power generators responsibility to ensure that power is available and can be despatched (they have a firm energy obligation and receive a Firm Energy Obligation Reliability Charge to ensure that this capacity is in place), even during El Niño. The power companies have, therefore, entered into take or pay agreements at a gas price of $4.20/MMBtu to purchase gas from the gas producers at the maximum gas requirement level (i.e. during El Niño). When El Niño is not in effect, the power companies pay take or pay liability payments to the gas producers for volume of gas that they have not taken below their contract amount. At present only 25% of the take or payment is paid, but this concession will end in 2012 and then the percentage which the power companies have to pay may increase to 80-90%, though this percentage has yet to be finally agreed. In order to mitigate the effect of this take or pay obligation, the power producers have on sold gas to industrial users (20-40 GBtu/day). When El Niño occurs, the power generators take all the gas from the gas producers (total ~500KBtu/day) and call back gas from the industrial users under the terms of the interruptible contracts. See diagram below.



*Until 2012 payments under take or pay commitments are limited to 25% of the payment amount. From 2013, this percentage may increase to 80-90% thus increasing liability to the power producers
** Interruptible contracts are for 20-40 Gbtu/day

Source: South-Court Ltd research

It is expected that current forecasting techniques should enable forecasters to predict the occurrence of El Niño several months before it starts, so by August/September of each year it would probably be known of El Niño will occur that year and that there could be reduced rainfall from December (the normal time that rainfall reduces when El Niño occurs).

CREG has the responsibility to ensure reliability of power supply during the El Niño period. CREG is, therefore, examining the possibility of LNG imports so imported gas can be supplied to the power generators in place of them having to enter take or pay commitments with the gas producers. As part of this initiative, CREG issued a Resolution to industry in December 2010 seeking industry's views on the possibility of LNG imports to support the Firm Energy Obligation Reliability Charge. The Resolution proposes a four-stage response so that by June 2012 an investment decision can be made to proceed with the necessary infrastructure and firm LNG supply contracts. In parallel to this market approach, CREG has commissioned a study to give information to the industry in Colombia on how LNG can be imported and possible industry structures (i.e. the way that industry can be set up). This study is being carried out by South-Court Ltd.

The potential LNG import requirement is estimated at 250-350 KBtu (250-350 MMScf/day). In order to ensure that sufficient power generating capacity is in place, the less efficient gas and coal power plants will be turned off but kept in an operational state so that they can be turned back on when additional gas powered generation is required.

The power producers are paid a firm Energy Obligation Reliability Payment of $14/MWh (approx. $5.60/MMBtu) to ensure that they are capable of producing firm energy, even at peak gas demand periods – periods of resource scarcity. This covers all elements of power supply, including different feedstock (gas/LNG, oil, coal) and the infrastructure required to deliver the feedstock to the powerplant. The power producers must therefore have the full 500 KBtu/day power capacity available. If gas is not available then their alternative is to use No 2 or No 6 fuel oil, which can result in a considerable financial penalty (the cost of Fuel Oil will be US Gulf prices plus shipping, plus transport costs to the inland markets). The price of gas sold into the market is regulated and based on a formula linked to US Gulf No 6 fuel oil prices. The price is determined on a six monthly basis (March-September and October- February) based on the previous six month's fuel oil prices.

The power producers sell power under different contract structures. Hydropower is normally sold under long-term contracts and if, during periods of El Niño, they were not able to produce power, then they would cover the shortfall by buying power from other power producers (gas, oil or coal). Where the power producer buys gas from LNG at a higher feedgas cost, it can charge a spot market price for power, which will mean that it should be able to recover all or part of its additional energy feedstock costs.

Colombia could meet this shortfall in gas through LNG imports. The issue is that the volume of LNG required on an annual basis is uncertain, as it will not be known in advance how severe El Niño is. Also, to import LNG on a short-term basis, the necessary facilities need to be in place. The LNG requirement, therefore, has two elements:

1. Facilities – An LNG regasification facility – either permanently in place or available on 3-4 months notice. The location for such a facility is not known.
2. LNG Supply – To be sourced on a requirement basis, to be advised at the time (could be 1-2 months ahead of delivery)

In order to develop such an infrastructure project, Colombia will need clear political support from the highest level to, ensure the necessary approvals and project development. Examples from Brasil and Argentina have shown the importance of government involvement and support to ensure quick development of LNG regasification facilities.

Any LNG import arrangements should be put in place for potential LNG imports by December 2014. It is important therefore that Colombia establishes soon a reliable source of gas for use at times of El Niño.

MAPA DE GASODUCTOS

Source: CREG

3. Characteristics of the Global LNG industry

3.1. Technical description of the Global LNG industry

This document focuses primarily on regasification options for Colombia. However, a broad understanding of the technical components of other elements of the LNG chain is also important in order to set LNG regasification options into context. The following, therefore, gives a brief introduction to these areas.

At the start of the LNG chain, gas for LNG is produced (upstream) in exactly the same way, from a technical standpoint, as it would be for a gas supply to a gas network, a grid operator or a major user[4]. Furthermore, at the other end of the LNG chain, once the regasified LNG (i.e. gas) is sent out into the pipeline systems or is used by final customers, then there is no difference to any other form of gas transported or used in the system. In summary, the production (start) and use (end) of an LNG chain is the same as any other regional or domestic use of gas.

The technical differences for the LNG sector all occur in the middle of the gas chain and are centred around how the fuel is transported and the physical processes that support it. These processes are: 1) liquefaction of the gas into LNG in a liquefaction plant, sometimes referred to as the export facility, 2) transportation in ocean-going LNG ships and lastly 3) the turning of LNG liquid back into gas in a regasification terminal. Below is a brief technical description of each element.

3.1.1. Liquefaction/export plant.

Liquefaction plants consist of four main sections. Gas treatment, liquefaction, liquid storage and finally the marine (LNG shipping related) loading.

i. Gas treatment the extent of gas treatment required depends entirely on the composition of the raw gas feed. A clean dry gas will need little processing, however a sour gas (high in sulphur) or a gas high in inerts (CO_2, Nitrogen) could need significant processing. The gas treatment facilities are often located at the liquefaction plant but, in theory, could be located anywhere between the plant and the gas reservoirs.

ii. The Liquefaction process constitutes the bulk of the equipment at a liquefaction plant. In its simplest form it operates in broadly the same way as a domestic fridge where a compressed refrigerant is expanded to create a cooling effect (Joule Thompson effect). The cold refrigerant is used to chill the gas stream until the gas becomes liquid (-161 degrees centigrade).

The two main process vendors for the liquefaction process are APCI (Air Products) and the Optimized Cascade Process (ConocoPhillips). These are the systems most commonly applied globally although there are others. Liquefaction plants are often referred to as “trains”, a typical modern day train

[4] There can be big differences commercially which will be considered later

being capable of liquefying between 3 to 5 million tonnes per annum of gas into LNG (some trains are larger - the largest are the Qatari trains at 7.8 mtpa).

Gas is used as the primary fuel source for most of a liquefaction plant's energy requirements e.g. compressor drivers, power requirements, control systems etc. Note that approximately 10-13% of the inlet gas sent into the liquefaction plant is used in its processes i.e. this gas is lost (used) and so represents a cost to the LNG exporter.

iii. Storage of the LNG at a liquefaction plant is an important and significant cost element. Storage is required because LNG is produced by the liquefaction process continuously, 24 hours a day, every day with very minimal interruption. Whereas the LNG ships will arrive only periodically – every few days depending on the size of the facility. Old (1970s built) LNG storage tanks would typically store 50,000m^3 of LNG whereas modern LNG tanks will hold 120,000 - 200,000m^3 of LNG. The LNG tanks are heavily insulated with double wall layers, perlite fill and high nickel content inner steel walls. The heavy insulation keeps the liquid cool (boil-off rate is approximately 0.05-0.10% per day). Most liquefaction plants would have at least two LNG storage tanks with the average being 3 or 4, some have significantly more.

iv. Marine loading is where the LNG is pumped from the LNG storage tanks into the awaiting ships. The LNG ships are docked alongside a purpose built jetty structure at the liquefaction plant where the liquid loading lines are attached to a ship's LNG manifold via the LNG unloading arms on the jetty head. There are also gas vapour return lines connected to the ship which are used during loading operations to maintain safe and controlled gas pressures within the LNG tanks and pipework systems of the terminal and the ship. LNG is pumped into the ship using the in-tank LNG storage pumps onshore. A typical loading operation would take 18 to 24 hours depending on the size of the ship.

Typically the depth of water (low tide) at the jetty berth is 12-14+ m but this can vary slightly depending on ship size. Cryogenic transfer lines to the jetty loading arms are very expensive and hence the length of the jetty (into open water to 12+m depth) is ideally kept as short as possible. Jetty length at the design phase is optimized against the need for additional dredging required to create sufficient water depth at the berth. A longer jetty will normally require less dredging (to achieve a 12+m depth at the berth), but will require longer (higher cost) cryogenic pipework. On the other hand, a shorter jetty will require less expensive (shorter) cryogenic pipework but likely will lead to much higher dredging costs. Jetty length for LNG terminals is typically 100-200m although this varies significantly depending on the coastal location (some are up to 2km long). It follows that jetty length and access to water at the right depth is always a significant design consideration in the siting and permitting processes for any LNG terminal.

Port facilities, availability of tugs, pilots, extent of other marine traffic, marine turning areas, wave and wind conditions, tidal considerations, seasonal weather patterns and many other factors will influence the marine area design.

3.1.2. Transportation (LNG shipping)

LNG is transported in specialist LNG vessels. These can only be used to transport LNG and cannot be used to transport any other products. Generally LNG ships are defined by the volume of LNG held in a ship's tanks. Sizes can vary from 17,000 cubic metres ($M^{3)}$ ships to 266,000 M^3 ships. The world's fleet currently comprises of approximately 361 vessels the majority being between 125,000 M^3 and

175,000 M^3 in size with the 125,000M^3 ships tending to be older (1970s). Most modern LNG ships are between 138,000M^3 to 165,000M^3 in size. A typical standard sized LNG ship takes between 2 -3 years to build, and is approximately 270-300m long, 50m wide with a water draft of 11-12m.

One of two types of containment systems are used on board – the "Moss Type Ships" which have 4 or more spherical tanks which can be seen protruding above a ship's deck (vessel in the foreground in the photograph), and the "Membrane Type " which have 4 or more box-type tanks which are flat to a ship's deck (vessel in the background in the photograph). Approximately two thirds of the current LNG tanker fleet and 80% of those on order are membrane vessels[5].

Source: Flower LNG

LNG ship propulsion systems are an important design feature; until recently they were exclusively steam turbine which allowed the boil off gas (i.e. boil off from the stored LNG on board) to be used in the ship's engines to generate steam. This was supplemented by bunker fuel (low sulphur fuel oil). Modern propulsion systems are still built as steam turbine although other systems are also now used e.g. diesel electric, slow speed diesel or other combinations. LNG ships move relatively quickly by marine standards with a cruising speed of 19 knots or more.

Boil off of gas from LNG ships is a key commercial issue. Older ships (i.e. most of the 125,000cm sized fleet) have a boil off in the range of 0.2-0.25% per day. Modern ships have a boil off rate of approximately 0.15% per day with some being lower. Ship size, propulsion system and boil off rates are key factors in the overall cost of LNG transportation.

3.1.3. Regasification Terminals

The Regasification Terminal consists of three main components; marine unloading, LNG storage and regasification.

i. Marine unloading facilities are essentially the same design as the facilities found at liquefaction plants (as described above). Although most regasification plants are located within existing operating ports, the marine port interfaces and issues (existing marine traffic, use of tugs, pilots etc)

[5] Membrane vessels are preferred as they take less time to cool-down and have lower Suez Canal transit fees.

can be more critical due to the natures of LNG. (Note: Many of the points made in Section 3.1.1. for marine loading at LNG liquefaction/export plants apply to the LNG import facilities as well).

ii. LNG storage at the regasification terminal is also very similar to the systems found at liquefaction plants with the same LNG tank designs being used. The main difference for import terminals is the smaller size of the in-tank pump systems which need only be designed to pump LNG at gas send out rates (import terminals are not required to pump LNG at the high rates required to load awaiting ships).

iii. Regasification is where the LNG is warmed allowing it to reform into a gas. Following pumping (low pressure) from the onshore LNG tanks, the LNG is further pumped (high pressure) into the regasification equipment where heat is added.

At many facilities worldwide, Submerged Combustion Vaporizers (SCVs) are utilized to warm the LNG. Here a hot gas flame is directly fired into a bath of water. The cold LNG is then passed via heat exchanger pipework through the hot water bath. The heat required to fully regasify the LNG is approximately 1.5 % of the flow of gas (called the fuel gas allowance or FGA). The fuel gas allowance is ordinarily free issue to the import terminal.

The type of heat required for vaporization is not high grade (i.e. not high temperature). Hence regasification systems often use renewable or low grade waste heat in whole or in part to regasify the LNG. Waste heat can be supplied from adjoining industrial facilities, power plants, sea water (called open loop vaporisation or ORVs), warm ambient air (in hot climates). In short, there is a very wide range of equipment and systems employed to provide the heat for vaporization depending largely on the availability of alternative heat sources, the ambient temperature and the temperature of nearby seawater.

Following regasification the gas is sent to customers or pipeline grids and is metered using the same type of gas metering systems commonly used in the gas industry (turbine meters, orifice plates, ultrasonic meters etc.).

3.2. Commercial considerations along the LNG chain.

3.2.1. Long term LNG transactions are the bedrock of the LNG industry

Since its inception in the early 1960’s, the sponsors and developers of LNG schemes (be it liquefaction, shipping or regasification) have strived to develop commercial and contractual models that adequately cover their risks in the LNG chain and provide sufficient return and certainty to the economic underpinnings of their investments. This is particularly important given that LNG chain developments are amongst the most capital-intensive energy projects in the world. Example numbers for 2011:-

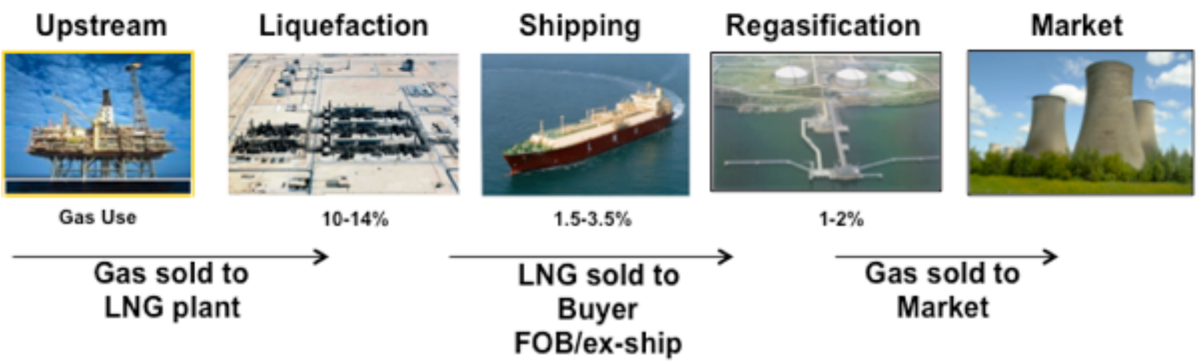
Cost of liquefaction:-	$1,000+ million per million tons/annum*
Cost of LNG ships:-	$250 – 300 million each (a typical scheme will need 4-5 ships)
Cost of LNG import:-	$1,000 million for a typical land based scheme (6-9 mtpa).

(*i.e. an $8 billion capital cost for an 8 million ton LNG plant)

The above does not include the cost of upstream development or pipelines to bring raw gas to the liquefaction plant or the cost of interconnection between the regasification plant and gas grid/markets. Even excluding these elements, given the above cost breakdown, a typical LNG chain of say 8.0 mtpa (11 Bcma) volume would cost in the order of $10-20 billion. Larger schemes, of which there are many, require even larger capital investments, for example the Gorgon Project Australia reached an investment decision in 2010 at a reported estimated cost of $36 billion excluding the regasification facilities.

The above cost considerations has led to the development since the 1960s of commercial schemes based on locked in long term (15-20 year) LNG sales contracts with "take or pay" commitments where buyers guarantee to purchase the LNG output from export facilities. The guarantees from large credible buyers provided LNG developer sponsors, investors and lenders the comfort required to invest the large sums involved. A further comfort was the price of LNG where, until recently, long term contracts were based on oil price indexation (where the price of LNG is directly linked to the price of oil via a formula in the LNG sales contract).

3.2.2. LNG commercial chain



Source: South-Court Ltd

Depending on the project structure, commercial agreements set out the rights and responsibilities between different parts of the LNG value chain.

3.2.3. Recent commercial developments – LNG trading.

Until a few years ago, the LNG business operated using the system of long term locked in contracts as generally described above. The amount of LNG sold via short term or spot contracts was very limited (less than 5%). However, since 2002, this pattern has changed with the growing importance of spot or traded LNG cargoes. In 2010 the global LNG business accounted for approximately 224 mtpa (307 Bcma), of this spot[6] transactions account for 15.7%. Unlike long term deals, spot

[6] Spot is a somewhat confusing term in respect of LNG but is generally used to describe the flexible trading or optimization of existing LNG cargoes on short term or spot transactions. These can be a single cargo or a string of cargoes over a few months. The key difference is that spot transactions are signed contractually when needed and are often signed with a short period between signing a contract and the delivery date of the LNG.

transactions are negotiated and signed on the basis of individual need, pricing and commercial terms. They often refer to specific cargoes (and ships) via delivery dates or to particular ranges of timing.

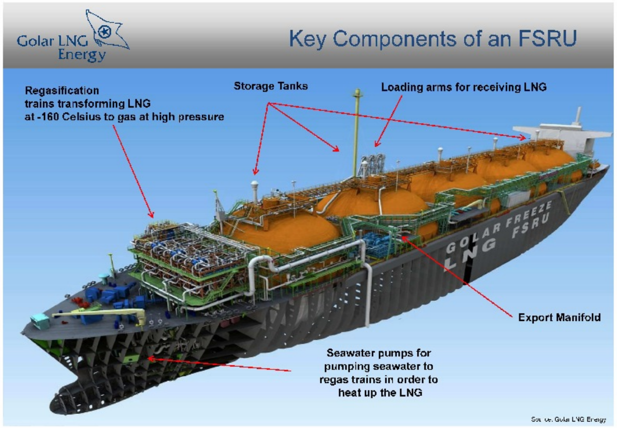
Pricing for spot transactions can be fixed or can float on any index. Typical spot indices for example are; the US, Henry Hub index, the UK National Balancing Point (NBP) index, the Belgium Zeebrugge Index (Zee), the Dutch Title Transfer Facility index (TTF) or indexation to oil related indices. There is no set pattern to the contractual terms of spot deals where each deal is negotiated and agreed separately. However, spot deals will all have key commercial drivers and features that will distinguish them from cargoes sold under long term contracts:-

- Spot cargoes always originate from LNG liquefaction facilities (export) which are already in operation,
- Spot deals would not, therefore, underpin the initial LNG chain investments (i.e. spot deals are an optimization not an underlying deal),
- Almost always spot cargoes would have already been purchased by an initial LNG buyer under an existing contract normally on an FOB (see Attachment 1 Glossary for definition) basis i.e. where the buyer provides the ship and loads the cargo at the initial seller's liquefaction (export) facility,
- The initial purchase transaction (normally FOB as above) would either include a buyer's right to divert or diversion (to new spot buyers) or would be agreed from time to time between the original LNG buyer and seller (often with an agreed sharing of any economic upside resulting from the diversion),
- Most LNG sales to Asia are firm (seller has to deliver and buyer has to take). Hence most spot cargoes originate from existing LNG sales contracts, which were initially targeted to flow into markets in the Atlantic (gas traded hubs). LNG to gas traded hubs if diverted but not delivered can be replaced (if needed) by pipeline gas on the traded hub,
- The number of truly spot transactions (i.e. cargoes which are not already sold) is very few (currently less than 20 per year). The vast majority of spot transactions arise from diversions (price optimization) of existing LNG purchase contracts by the original LNG buyer.
- Spot transactions are ordinarily signed only a short time before the cargo is delivered (normally a few months but it can be just days in advance in times of high gas price volatility)
- Countries such as Argentina, Brasil, Dubai and Kuwait are using FSRU's (see Attachment 1 Glossary for definition) to import LNG. These projects have been developed quickly (see later for details). Argentina and Brasil have relied on the short-term LNG market to source their LNG. In 2010 Argentina imported 1.9 mtpa LNG (approx. 30 cargoes) and Brasil 2.7 mtpa (approx., 45 cargoes) and in 2011 imports are expected to rise. These cargos were all imported from the short-term market, securing the volume 3-5 months before the start of the winter importing period. Dubai has purchased part of its volume on a 20 year long-term contract, the balance being bought short-term, and Kuwait has purchased its LNG under 2-3 year term arrangements.

Since the construction of an LNG export facility takes at least 4 years from the award of EPC contract (see Attachment 1 Glossary for definition), it follows that any party wishing to purchase LNG within 4 years is de-facto purchasing LNG which will contain many of the features of spot transactions as above– i.e. the LNG will undoubtedly already be purchased and will originate from LNG export facilities which are already in operation. This is an important consideration that will be discussed in detail later.

For the purposes of this report, "Spot" is assumed to be a single cargo and "short-term" any contract to supply LNG of less than two years duration.

3.2.4. Floating Storage and Regasification Units (FSRUs), key features



Source: Golar

Land based LNG regasification terminals as described above represent a relatively small portion of the overall cost of the LNG chain (circa 10%). Nonetheless they are still expensive with a typical cost in the region of $1 billion for a new 7 mtpa (9-10 Bcma) sized facility. Since any land based LNG import scheme, regardless of size, always needs a jetty, dredging, cryogenic lines, LNG tanks, connecting pipeline etc. then it means, no matter what size the facility or its utilization rate (how often used), the costs remain of the same order. In other words, a scheme half the size is not half the cost. A key advantage of FSRUs is the speed at which they can be developed. Whereas a land-based LNG regasification terminal may take four years to build and be operational, an FSRU system can be operational within 18-24 months of the date of investment decision.

Source: Excelerate

Another issue for LNG regasification (import) terminals is local and federal permits. Ideally the import of LNG would occur close to the final market or pipeline gird. This means suitable coastal areas in which to site a regasification terminal are often likely to be close to centres of population, people, houses, towns, cities etc. Whilst it may technically be possible to site LNG import terminals in these areas and still meet stringent proximity, zoning and environmental requirements, it does not mean that local authorities will allow it. In many cases obtaining the necessary permits for new LNG schemes is almost impossible (e.g. USA east and west coasts).

An answer to the cost and permitting issues faced by land based regasification schemes was developed to a reality in 2005 by Excelerate Energy of Houston Texas[7]. Here Excelerate Energy developed the Floating Regasification and Storage Unit (FSRU) and took delivery of the world's first FSRU from Korea in mid 2005.

An FSRU is essentially a standard LNG ship with the addition of regasification equipment on deck. This allows the ship to take LNG from its on-board tanks, regasify the LNG on-board and discharge high-pressure gas rather than LNG from the ship. The regasification, gas discharge and ancillary equipment on-board can either be designed and built into the ship during the ship's original construction (as a new build) or the equipment can be installed by a ship yard as a conversion of an existing LNG ship to an FSRU vessel. A new build FSRU takes 24 to 30 months to build, a conversion would be shorter at around 12 months. New build or conversion times, however, can vary widely depending on shipyard availability. The cost and operational flexibility of an FSRU varies. A new build, such as the Excelerate or GdFSuez vessels, can operate as an FSRU and trade as a standard

[7] FSRU schemes were first developed by the US utility El Paso and later pursued by Excelerate Energy following El Paso's partial withdrawal from the LNG business in the early 2000's

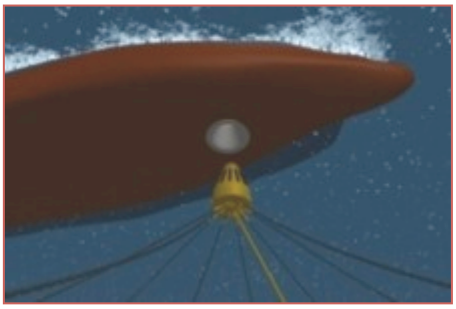
vessel. The conversion of an older vessel, which Golar has done in Brasil and Dubai, is possible but following conversion the vessel would not then normally operate as a standard LNG trading vessel. FSRU conversions, therefore, tend to remain in port as a static floating regasification terminal, even when no cargoes are being received.

Presently there are three companies actively involved in the FSRU market with FSRU ships in operation. Excelerate Energy (USA) which has 8 FSRUs in operation (138,000m^3 to 151,000m^3 in size), Golar LNG (Norway) with 4 FSRUs in operation (125,000m^3 to 137,000m^3 in size) and one in conversion and GdFSuez (France) with 2 FSRUs and one FSU[8] in operation (145,000m^3 in size). There are also other players planning to enter the market and any developer must actively research the available options and costs prior to making any investment.

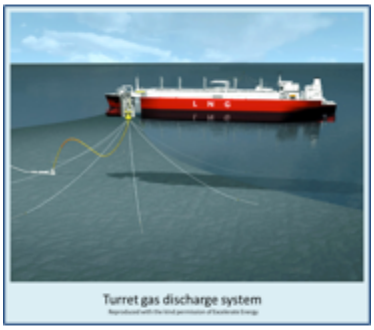
FSRU Gas Discharge systems.

LNG loading systems employing on-board FSRUs are essentially the same as the equipment on a standard LNG ship as previously described in earlier sections. However, the FSRUs also need to send out gas into pipeline systems, and there are some key differences compared to any other LNG ship. Gas discharge from FSRUs is achieved via two systems:-

i. The submerged turret unloading system, is an offshore discharging system connected to subsea gas pipelines. The turret is manufactured by Advanced Production and Loading (APL of Norway) and has been used in the oil industry extensively for FPSO (see Attachment 1 Glossary for definition) operations for many years. Most but not all LNG FSRUs use this technology.



Source: Excelerate



Turret gas discharge system

Source: Excelerate

The turret is connected to a flexible riser pipeline and sub-sea gas pipeline. The flexible riser pipeline and the turret system are held in place by a pattern of anchors and semi-submerged supports set into the sea floor. The turret is buoyant and when not in use is held in position at a depth of approximately 30m below the surface. The turret in the open ocean is marked only via a marker buoy with none of the systems components being visible on the surface. The system requires ideally a water depth of 100+m for its installation and operation.

To make the connection to the turret the FSRU has a purpose built turret reception system (normally in the bow) which is essentially a large round opening in the base of the ship's hull. The FSRU is positioned above the turret which is then winched up into the ships turret reception system. After the gas connection is established gas can then be sent from the ship through the turret and into the sub-sea pipeline.

ii. Gas Jetty system, allow the FSRU to discharge gas via a simple gas connection on its deck. The FSRU connects to a high-pressure gas unloading arm which is located on a jetty. The FSRA moors alongside the jetty in the same way it would if delivering LNG. The gas jetty marine requirements are essentially the same as those required for a standard land based import terminal although since

[8] FSU Floating Storage Ships – An FSU (Floating Storage Unit) is a standard LNG ship with minimal modification to allow it to stay on station at a jetty, receive LNG into its tanks and discharge the LNG when needed. Effectively an FSU is a replacement for onshore LNG tanks.

no LNG is discharged there is no need for cryogenic pipelines or any other LNG related equipment on-shore.

Source: Excelerate

Some FSRUs are equipped for turret discharging, some for gas jetty discharging and some have both.

FSRU vaporisation systems.

As discussed in earlier sections the type of heat required during regasification is not high grade (i.e. is not high temperature). FSRUs use two possible heat sources –"closed loop" where heat is added on board using boil off gas (via steam raised from the ship's boilers) or "open loop" which uses sea water. Some FSRUs are equipped with closed loop only, some can use both closed and open loop technology.

Source: Excelerate

Closed loop uses a portion of the gas (LNG) on board as fuel gas. For FSRUs the fuel gas used is 2% or higher of the gas send out. (Note - this is higher than the equivalent fuel gas used in land based terminals). Also since the ship is burning gas there could be additional planning and environmental considerations (for example NOx and SOx emissions).

Open loop uses sea water and so use very little gas as fuel for vaporisation, typically 0.5% or less (for power generation/pumping). However, open loop vaporisation may not be allowable in some locations. Planning and marine authorities in some locations have concerns about the effects of water cooling in the vicinity of the FSRU and its effects on marine life (in particular microscopic organisms), or concerns about the death of small marine life if ingested into a ship's pump and heat exchange systems.

3.2.5. FSRU commercial considerations and operating systems

FSRUs are LNG ships. However, when operating as FSRUs they are effectively import terminals (floating) but subject to maritime regulations. From a functional perspective an FSRU has some common features with a land based import terminal. However, it can be quite different to a land based scheme in respect of marine loading and gas send out, this has a marked impact on the systems of operation which in turn impacts on the commercial development of the scheme and the associated LNG supply options.

A land based regasification terminal simply takes delivery of LNG at its jetty and stores the LNG in its tanks until needed as gas. In the case of an FSRU scheme once the LNG is sent out from the FSRU (as gas) then the ship is empty and needs to refill with LNG. It can either
a) "empty and leave" – where it departs to sail to an LNG export plant and take delivery of the next cargo then return to the import location or
b) "stay on station" – where it does not leave the import location and instead takes delivery of new LNG directly from another LNG ship which delivers to the FSRU (ship-to-ship) to refill the FSRU's LNG tanks.

Empty and leave

In the case of "empty and leave", using a single gas discharge system, once the vessel is empty it will have to go off station to reload an additional cargo. During this period the system will not be able to send out gas. This interruption in gas send-out may be acceptable in some situations depending on the nature of the gas market the FSRU is delivering to. In these cases the "empty and leave" configuration is a viable option. This is the system employed at the Excelerate Energy scheme located at Teesside UK which is a jetty based scheme and also uses the same system as the Excelerate Energy scheme in the US Gulf of Mexico, Gulf Gateway, which is a single buoy (single turret unloading) offshore design i.e. there is no jetty. In both these locations there are periods when the gas send out is interrupted. However, this is not an issue at these locations given that both terminals feed gas into fully traded and extensive gas pipeline grids where any interruption in gas supply can be mitigated. If there is enough gas "line-pack" then gas supply may not have to be interrupted.

In case of "empty and leave", where an interruption to the gas send out is not desirable or feasible then an option is to build two gas discharging systems and use two FSRUs. One FSRU is connected and discharging gas whilst the second FSRU will be at sail to pick up the next cargo. When the second (now full) FSRU arrives back at the import location it connects to the second gas discharge location to discharge its gas. The first FSRU is then disconnected and is clear to set sail to pick up the next cargo (from whatever source). In this way the flow of gas is continuous and switches between the two FSRUs. This is the scheme employed at the Excelerate Energy scheme near Boston (USA - NorthEast Gateway) and the GdFSuez scheme also near Boston (Neptune). Both of these schemes use twin offshore turret unloading systems to maintain a constant flow of gas.

Stay on station

These schemes utilise a single FSRU in a semi-permanent configuration where the FSRU is always connected to the gas discharge location via a jetty configuration or via a sub-sea turret buoy system. The FSRU does not leave; it stays at the import location, still attached to the gas pipeline network. Once the FSRU is empty (or otherwise ready for a new delivery of LNG) it is refilled with LNG delivered directly ship-to-ship from an arriving ship. This second arriving LNG ship does not need to be an FSRU or be modified, as it is not discharging gas, it discharges LNG only. It is a standard LNG carrying ship and would arrive and discharge its cargo of LNG in essentially the same way as it would at a land-based terminal.

The most recently installed FSRU terminal schemes worldwide have mostly adopted this configuration using jetty mounted systems, for example; Excelerate Energy's schemes at Bahia Blanca (Argentina) and Mina Al-Ahmadi (Kuwait) and the Golar LNG schemes at Pecem (Brasil), Rio de Janeiro (Brasil) and Jebel Ali (Dubai)

There is also a proposed scheme at Livorno (Italy), which again adopts the "stay on station" configuration, but in this case the scheme will use a single turret offshore arrangement where the arriving LNG ships will discharge at the FSRU/turret location some 34 kilometres out to sea. The FSRU remains on the turret discharging system and the second ship is moored along side. The two ships stay attached together via mooring lines until the LNG discharge operation is competed at which point the LNG discharge pipelines and the mooring lines are detached and the delivering ship is clear to leave. Off-shore ship-to-ship LNG transfer is arguably more complex from a marine perspective than gas transfer via a jetty arrangements because the two ships if off-shore are subject to more movement (waves and wind effects) given the open sea conditions. Off-shore LNG discharge requires careful consideration of the prevailing marine conditions and the possible effects of bad weather.

3.2.6. FSRU cost considerations

One of the great advantages of FSRU schemes is the much lower capital cost and speed of planning and construction. The following is a very broad assessment of the relative costs (capital and operating) of the various FSRU configurations:-

Cost item	Approximate cost US $
FSRU new build	250 million - 300 million each
FSRU conversion	50 million - 100 million per ship
APL turret installation	25 million each
Turret anchors and manifolds	25 million per turret
Sub-sea pipelines	1 million – 2 million per km
Jetty new build	20 million+
Jetty head mooring systems	20 million
LNG loading arms and systems	15 million per jetty head
Gas discharge arms and systems	5-10 million per jetty head
Cryogenic pipework across jetty	5-10 million per jetty head
Ship-to-ship LNG discharge systems	5 million
Nitrogen injection (if required)	10 million
FSRU charter rate (2010)	$ 100,000 – 200,000/d (Note: the wide range depends if the charter is for a new build or the conversion of an older vessel)
Standard ship charter rate (2010)	$ 60,000 – 80,000/d
FSRU gas losses	2+% of gas send out

NOTE: These figures are estimates only and accurate costs should be obtained based on the specific offshore and port locations in Colombia.

Whilst the costs above are not insignificant it must be kept in mind that FSRU schemes do not need on shore LNG tanks ($150-200 million per tank). Also the most expensive parts of the FSRU system (the FSRU units themselves) can be chartered for part of a year if the market requirements is only for part-year gas delivery. The configuration of the scheme, its operating modus (empty and leave or stay on station), the distance of off-shore systems from the coastline etc. all have a significant impact on the overall costs of the terminal scheme.

3.2.7. Scheme design and impact on LNG supply options

As discussed above, for any LNG import scheme desiring to purchase LNG within the next 4 years it almost certainly means that the LNG is already “bought” and that the LNG export facilities producing the LNG are already in existence and operating. Fitting the FSRU scheme configuration to available LNG, the capability of existing LNG suppliers and the available LNG/FSRU shipping capacity are, therefore, all key considerations. In other words, designing an FSRU scheme using only local parameters and design inputs (for example to lower sponsor costs) may not give the best overall optimal solution.

For example an "empty and leave" system requires that only FSRU ships can dock at the facility since the delivering ship has to be an FSRU (either turret or gas jetty). It also means that the original facility producing the LNG will need to deliver LNG to the FSRU on an FOB basis[9]. The use of only FSRUs to deliver LNG will significantly limit the possible number of ships that can service the facility since the global LNG shipping fleet is 361 vessels whereas the global FSRU fleet is less than 15. LNG export facilities selling LNG on an FOB basis could also be problematic since:

i. Most export facilities sell LNG on an ex-ship basis (delivered to the import terminal) and
ii. The LNG is likely already sold (see above) and the existing buyer may not be a holder of existing FSRUs (the only exception being GdFSuez which has a portfolio of LNG supplies whereas Excelerate and Golar do not). The LNG supplier in this case would need to charter an FSRU if available.

Given the above it is no coincidence that the most recently built FSRU schemes have all been constructed using a "stay on station" approach since

i. LNG can be delivered to the import location using standard LNG ships (larger global fleet)
ii. Deliveries can be accepted on an ex-ship basis (which opens up the LNG options significantly)
iii. The FSRU need only be on station when required (e.g. seasonal requirements) and
iv. The roles of the FSRU/import terminal can be separated from the role of the LNG supplier (which again opens up the LNG supply options significantly).

There are no set rules or easy answers in respect of configuration, technical and commercial features of an FSRU scheme (new arrangements are created all the time). The key is to assess the scheme from an overall standpoint encompassing terminal, LNG requirement and business structures and not to focus on one aspect only.

The advantages/disadvantages of the various FSRU options are considered in detail later and are also set against the current shipping market, FSRU market and LNG supply/demand situation

3.2.7.1. Non FSRU and other novel technologies

FSU with on shore regasification

An FSU (Floating Storage Unit) is essentially a standard LNG ship with minimal modification to allow it to stay on station at a jetty, receive LNG into its tanks and discharge the LNG when needed. Effectively an FSU is a replacement for onshore LNG tanks. Limited ship modifications may be needed to handle LNG in/out manifold configurations, seawater intake capable of handling higher silt/particulates in the port area (since there is often a higher silt/particulates exposure in a jetty port area as compared to open sea) and other issues. Nonetheless the modifications are minimal compared to a full FSRU conversion.

FSU schemes do not need regasification equipment on board, instead regasification is carried out onshore or on the jetty in a regasification unit designed to take LNG from the FSU and regasify into the pipeline grid when needed. LNG is delivered into the FSU from the arriving (again standard) LNG

[9] It is possible to transfer the LNG ship-to-ship into an FSRU prior to the FSRU arriving at the import location although the number of such transfers conducted to date is very few and every transfer ship-to-ship prior to arrival at the import location will increase the delivered cost of LNG.

ship using jetty mounted LNG loading and discharge arms. The GdFSuez Mejillones (Chile) project uses this configuration.

A very similar scheme with the regasification equipment mounted on the jetty is currently being built in Malacca (Malaysia) for Petronas. This scheme will use two FSU ships in an end-to-end configuration to increase the available LNG storage of the terminal.

FSU with regasification barge

This is a similar concept to the FSU + onshore or jetty regas except in this case the regasification is carried out on a purpose built regasification barge. The barge can be open loop, closed loop, air vaporisation or whatever configuration is required. To date no scheme has been built using this configuration although the technology to make such schemes viable is easily obtained.

3.2.8. Existing FSRU vessels and terminals

Key commercial details of existing FSRU ships

i. Excelerate Energy fleet

Ship Name	Builder & year	Manager & flag	Send out system	Storage type & Capacity cm LNG	Draft	Boil off per day	Regas system	Gas send-out rate million scfd and system
Excelsior	DSME 2005	Exmar Belgium	APL turret plus jetty discharge	Membrane 138,000	11.5	0.155%	Open & Closed	500 open 400 closed 690 max
Excellence	DSME 2005	Exmar Belgium	APL turret plus jetty discharge	Membrane 138.000	11.5	0.155%	Open & Closed	500 open 400 closed 690 max
Excelerate	DSME 2006	Exmar Belgium	APL turret plus jetty discharge	Membrane 138,000	11.5	0.155%	Open & Closed	500 open 400 closed 690 max
Explorer	DSME 2008	Exmar Belgium	APL turret plus jetty discharge	Membrane 150,900	11.6	0.150%	Open & Closed	500 open 500 closed 690 max
Express	DSME 2009	Exmar Belgium	APL turret plus jetty discharge	Membrane 150,900	11.6	0.150%	Open & Closed	500 open 500 closed 690 max
Exquisite	DSME 2009	Exmar Belgium	APL turret plus jetty lines	Membrane 150,900	11.6	0.150%	Open & Closed	500 open 500 closed 690 max
Expedient	DSME 2009	Exmar Belgium	APL turret plus jetty discharge	Membrane 150,900	11.6	0.150%	Open & Closed	500 open 500 closed 690 max
Exemplar	DSME 2010	Exmar Belgium	APL turret plus jetty discharge	Membrane 150,900	11.6	0.150%	Open & Closed	500 open 500 closed 690 max

ii. Golar LNG

Ship Name	Builder	Manager	Send out system	Capacity cm LNG	Draft	Boil off per day	Regas system	Gas send-out rate million scfd and system
Golar Spirit	Kawasaki 1981	Golar MI	Jetty line	Moss 128,000	11.5 (est)	0.25% (est)	Closed	283
Golar Winter	DSME 2004	Golar MI	Jetty line	Membrane 138.000	11.5 (est)	0.155% (est)	Open &Closed	500

Golar Freeze	HDW 1977	Golar MI	Jetty line	125,000	11.5 (est)	0.25% (est)	Open	400
Golar Frost	HHI Japan 2004	Golar	Turret plus jetty lines	137,000	11.6 (est)	0.155% (est)	Open	500 (est)

iii. GdFSuez

Ship Name	Builder	Manager	Send out system	Capacity cm LNG	Draft	Boil off per day	Regas system	Gas send-out rate million scfd and system
GdFSuez Neptune	Samsung 2009	Höegh LNG MI	APL turret	Membrane 145,000	11.5 (est)	0.15% (est)	Closed	750
GdFSuez Cape Ann	Samsung 2010	Höegh LNG MI	APL turret	Membrane 145,000	11.5 (est)	0.15% (est)	Closed	750

3.2.9. Details of existing FSRU import terminal locations (in order of date built)

The section below describes details of the current FSRU LNG regasification terminals. For ease if reference, the different options are references to the proposed options for Colombia as set out in Section 3.3.

3.2.9.1. Excelerate Energy – 2005. Gulf Gateway, Gulf of Mexico USA (Colombia Option 2)

Gulf Gateway the world's first FSRU terminal was installed by Excelerate Energy in 2005. The terminal is located some 114km offshore Louisiana (USA) and uses a single APL turret system. The terminal connects to existing sub-sea pipelines and is permitted to operate in open or closed loop configurations. Gulf Gateway also incorporates a fixed platform to house necessary pipeline interconnection and metering systems.

3.2.9.2. Excelerate Energy – 2007, Teesside, UK (Colombia Option 5)

The Teesside terminal is the world's first use of an FSRU in a jetty type discharge arrangement. The terminal was built in the river Tees (North East England) via the conversion of an existing jetty to FSRU use. The FSRU moors at the jetty and discharges its cargo as gas via gas discharge arms mounted on the jetty in closed loop mode. Once empty the FSRU leaves the location to allow the next FSRU to deliver. The terminal (shore side) also features nitrogen injection equipment in order to adjust gas quality to match UK specifications (UK gas specification ranges are relatively narrow).

Source: Excelerate

3.2.9.3. Excelerate Energy – 2007, NorthEast Gateway, offshore Boston, USA (Colombia Option 4)

Excelerate's NorthEast Gateway terminal is a twin APL turret arrangement located 20 km offshore Boston (USA). The twin turret arrangement allows a continuous send out of gas into the terminals sub-sea pipelines when used with two FSRUs in rotation. The terminal is permitted for closed loop regasification only.

3.2.9.4. Excelerate Energy – 2008, Bahia Blanca, Argentina (Colombia Option 6)

The Bahia Blanca (Argentina) terminal, sponsored by Excelerate Energy, YPF and Repsol, is located 400 km south of Buenos Aires. It is a jetty type arrangement using many of the features of Excelerate's Teesside facility. The FSRU connects to the jetty head via gas discharge arms and regasifies in closed loop mode. Unlike Teesside it can accept delivering (standard) ships which moor directly alongside the FSRU (i.e. the delivering ship is not connected directly to the jetty). LNG transfer is effected ship-to-ship by connection of the delivering ship directly to the FSRU via flexible cryogenic hoses.

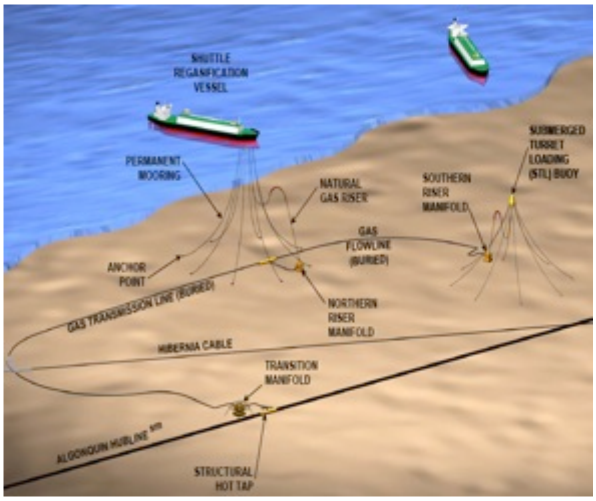
Source: Excelerate

3.2.9.5. Golar LNG - 2008. Pecem Brasil (*Golar Spirit*) (Colombia Option 6)

Petrobras, the terminal sponsor, commissioned the Pecem (NE Brasil) import terminal in 2008. The terminal uses an existing jetty that has been modified to accept an FSRU and delivering ship in a side-by-side across the jetty type arrangement. The FSRU *Golar Spirit* is moored semi-permanently and discharges gas via two gas discharge arms mounted on the jetty head. The FSRU is also connected via 3 LNG loading lines that allow the FSRU to take on board new LNG from the delivering ship. The delivering ship is moored on the other side of the jetty and discharges LNG via 3 x LNG discharge arms in a standard configuration.

3.2.9.6. GdFSuez – 2008, Neptune, offshore Boston, USA (Colombia Option 4)

GdFSuez first entry into the FSRU markets with the construction of the Neptune project, offshore Boston (USA). The arrangement for Neptune is the same as that used by NorthEast Gateway i.e. a twin APL turret arrangement offshore. To service the Neptune project GdFSuez also ordered two new FSRU ships, the *Neptune* and the *Cape Ann,* which came into service in 2009 & 2010.



Source: GDFSuez

3.2.9.7. Golar LNG – 2009. Guanabara Bay, Rio de Janeiro, Brasil (*Golar Winter*) (Colombia Option 6)

Petrobras, the terminal sponsor, commissioned the Guanabara Bay import terminal in 2009. The terminal uses a purpose built near-shore (island type) jetty head arrangement located 5km off-shore. Although the jetty head is offshore the arrangements and operation of the jetty head is very similar to the Pecem terminal with a side by side across the jetty type arrangement. Gas from the FSRU discharges via the gas discharge arms on the jetty head and is sent to the gas grid via the connecting (5km long) subsea pipeline.

3.2.9.8. Excelerate Energy – 2009, Mina Al Ahmadi, Kuwait (Colombia Option 6)

The Mina Al Ahmadi terminal, originated by Kuwait Petroleum Company, uses an existing jetty modified to accept FSRUs. The FSRU moors to the jetty and connects as usual via gas discharge and LNG loading arms. The delivering LNG ship moors to the same jetty via a separate jetty head in an end-to-end type configuration. LNG is then discharged from the delivering ship to the FSRU via a separate bank of LNG discharge arms and cryogenic pipelines to the FSRU.

Source: Excelerate

3.2.9.9. GdFSuez – 2009. Mejillones, Chile (Colombia Option 7 land based regasifiers)

Sponsored by GdFSuez the terminal uses a modified standard LNG ship to receive LNG prior to sending the LNG to a shore based regasification system. This avoids the need for on shore tanks (which in the particular example were planned for construction at a later time). LNG transfer is effected across the jetty (i.e. similar to the Brasil terminals).

Source: GDFSuez

3.2.9.10. Golar LNG - 2010. Jebel Ali, Dubai (*Golar Freeze*) (Colombia Option 6)

Sponsored by Dubai Supply Authority (DUSUP) and advised by Shell Global Solutions, the terminal involved the construction of a new jetty and breakwater to allow the FSRU to moor semi-permanently to the jetty head. The FSRU is connected via gas discharge arms to the jetty head. The FSRU *Golar Freeze* is moored semi-permanently to the new jetty and discharges gas via gas discharge arms mounted on the jetty head. The delivering ships moor directly alongside the FSRU (i.e. delivering ship is not moored directly to the jetty). LNG transfer is effected ship-to-ship by connection of the delivering ship directly to the FSRU via flexible cryogenic hoses.

Source: Golar LNG

3.2.9.11. Golar LNG - planned 2011/12, Livorno OLT Offshore, Italy (*Golar Frost*) (Colombia Option 3)

The *Golar Frost* is currently undergoing conversion to FSRU service. Unlike all previous conversions of existing LNG ships the *Golar Frost* will also incorporate a new fixed (i.e. turret cannot disconnect and stays permanently fixed) turret gas discharge system and is also equipped with LNG loading arms on-board. The FSRU, once in service, will be moored to the seabed via the turret discharge system through which gas from the FSRU will be discharged. LNG will be delivered to the

Source: OLT Toscana

FSRU via the on-board LNG loading arms from the delivering ship which will moor directly to the FSRU.

3.2.10. Approximate sizing and marine requirements for the various schemes

Site selection, zoning and permitting are highly specialized areas and are not within the scope of this report. CREG must undertake a detailed site selection study with an expert in order to identify suitable ports and the necessary technical requirements for an LNG import project. The following is, therefore, included as a rough indication only of the land areas, port requirements etc. for typical LNG import schemes. Each LNG import scheme is specifically designed for the location and to meet market requirements.

Land area requirements for land based import schemes vary widely depending on availability and proximity to other buildings and population centres. An area of 80-100 + acres would not be unusual. Exact siting and proximity zones are established following careful study of vapour cloud dispersion, heat radiation, risk analysis and many other factors.

Size of jetty and marine requirements are broadly the same for an FSRU application as they would be for a land based LNG terminal. Jetty length depends on depth of water, up to 14+ m at the berth (low tide). Width of jetty required for LNG across jetty loading is approximately 50m. In addition the jetty must be able to accommodate the increased weight of LNG arms, emergency systems, cryogenic lines, expansion loops etc.

Marine approach requires 12 to 14+m of water depending on port procedures and ship characteristics. Difficult or twisting approach channels can cause problems in some cases requiring dredging. In addition a turning circle of 1.5 ship length adjacent to the jetty head is normally required (i.e. a turning circle of 450+m diameter). LNG ships are handled in port by 3 tugs with an additional tug on standby. Tugs are normally at least 60 ton bollard pull. Marine exclusion zones are applied (location specific) to moving and static LNG ships, these can be in the range 500-2000 metres in front of or behind a moving LNG ship. Also once on berth other large ships would not be allowed to pass within certain distances (circa 70 m) and are also speed restricted.

Offshore turret systems are normally applied in deep water only i.e. 100m or over. There are now some designs which allow much shallower depths although, it is understood, that none have yet been installed for gas/LNG usage. FSRUs are equipped with bow thrusters and so can dock at the turret without the need for tugs. Any ship-to-ship operations, however, would require the use of tugs.

3.3. Summary characteristics, advantages, disadvantages of import terminal configurations.

	Scheme	Configuration	Advantages	Disadvantages	Apx costs
1	Land Based	LNG discharge jetty Onshore tanks (with total storage approx. 200,000m^3) Onshore regasification	Long term flexibility and expansion options, continuous and flexible gas send out, uses standard ships only, variety of regas options (waste heat, air vaporisation, open or closed loop)	Very expensive, large land requirement, local permits could be difficult, 4 year built time after permits obtained. Environmental impact of on land facility.	Capex $ 1 billion+ No ship charter costs
2	FSRU with offshore single turret	Single offshore buoy LNG is stored and regasified on the vessel and supplied to market via the single turret	Low cost, no or few onshore facilities, local permits much easier, shorter build time (2 years or less), no tug requirement	Gas supply interrupted, requires FSRU turret ships only (standard ships cannot connect), will limit the supply options	$ 100 million+ capex depending on length of sub-sea line. FSRU charter = $ 55 – 75 million per annum
3	FSRU with offshore single turret and ship-to-ship LNG transfer from the "delivery" vessel to the FSRU	Single offshore buoy with standard LNG ships delivering to the FSRU ship-to-ship. The FSRU stores the LNG and regasifies the LNG and sends gas to market via the single turret	Low cost, no or few onshore facilities, local permits much easier, shorter build time (2 years or less), LNG delivery using standard ships	Not all ship operators will be willing to deliver (ship-to-ship requires additional procedures), could limit supply options, requires very benign marine environment	$ 100 million+ capex depending on length of sub-sea line. Higher operating costs costs to monitor FSRU location FSRU charter = $ 55 – 75 million per annum
4	FSRU with twin offshore turret	Twin offshore buoys. FSRU attaches to the turret, LNG is stored and regasified on the vessel and supplied to market via the single turret	Lower cost, no or few onshore facilities, local permits much easier, short build time (2 years or less)	FSRU turret ships only (standard ships cannot connect), requires two FSRUs, will limit the supply options	$ 150 million+ capex depending on length of sub-sea line. FSRU charter = $ 110 – 150 million per annum

5	FSRU jetty	Single jetty head with gas discharge. FSRU brings the LNG to the jetty and LNG is stored and regasified on the FSRU and supplied to market via high-pressure pipe.	Low cost (can use existing jetty), short build time (18 months possible)	Gas supply interrupted, requires FSRU ship only (standard LNG ship cannot connect), will limit the supply options	$ 50-100 million+ capex . FSRU charter = $55-75 million per annum
6	FSRU jetty with FSRU on station	Single jetty head with gas discharge and LNG transfer lines. Standard LNG vessel brings the LNG to the jetty. The LNG is then transferred to an FSRU. LNG is stored and regasified on the FSRU and supplied to market via high-pressure pipe.	Low cost (can use existing jetty), short build time (2 years or less), takes delivery from standard LNG ships, continuous gas discharge	LNG transfer lines add cost	$ 100-150 million+ capex FSRU charter = $55-75 million per annum
7	FSU jetty with FSU on station	Single jetty head with onshore regas and LNG transfer lines. Standard LNG vessel brings the LNG to the jetty that is transferred to an FSU. LNG is stored on the FSU, regasified using onshore regasification facilities and supplied to market via high-pressure pipe.	Low cost (can use existing jetty), shorter build time than land based (2 years), takes delivery from standard LNG ships (no need for an FSRU), continuous gas discharge	Onshore regas and LNG transfer lines add capital cost. Such a facility would need maintenance during periods of non-use.	$ 150-200 million+ capex FSU charter = $22-29 million per annum
8	Regas jetty with no FSU	Single jetty head with onshore regas and LNG transfer lines. Standard LNG vessel brings the LNG to the jetty and is slowly discharged to the regas system. Delivering ship stays on jetty throughout (7 days+).	Low cost (can use existing jetty), shorter build time than land based (2 years), takes delivery from standard LNG ships. Does not use an FSRU or an FSU. No need for a charter agreement – pay for ships via amended ex-ship price. Givers flexibility for supply outside El Niño.	Onshore regas and LNG transfer lines add capital cost but only requires one set of LNG arms. Gas supply interrupted when ship leaves. Suppliers would need to agree a long discharge time – some ships may not be able to slow unload (this would need to be checked).	$ 125-175 million+ capex LNG ex-ship may be marginally more expensive

			p	Such a facility would need maintenance during periods of non-use.	

Note 1 – cost assumptions as above are very approximate and are provided here to give an order of magnitude only. Actual costs will vary widely depending on particular site conditions, the availability of existing jetty infrastructure, dredging requirements, marine and port conditions etc.
Note 2 – costs notes above do not include costs for onshore connecting pipelines.
Note 3 – Under options 2 & 5 where there will be a break in supply due to only one vessel being used, it may be possible to mitigate this shortfall through gas line pack. If this is possible, then the applicability factor would increase.
Note 4 – None of these options assume constructed LNG storage tanks.

4. Potential application of FSRU schemes in Colombia

4.1. What is the requirement for LNG in Colombia

Theoretically, Colombia is self sufficient in gas. However, the impact of El Niño as addressed in Section 2 if this report can lead to short-term and somewhat unpredictable gas supply shortfalls, in summary...

- The El Niño effect can result in a significant reduction in rainfall in Colombia and a corresponding reduction in power generation from hydropower installations;
- El Niño ordinarily occurs between December and April but the duration can be longer;
- In some years El Niño does not happen, it's difficult to predict;
- Modern forecasting techniques should, however, be able to predict the start of an impending El Niño with 3- 4 months advance notice (i.e. notice by August/Sept);
- If an El Niño happens then the increased need for gas to offset the gap left by reduced hydropower is in the order of 300-400 million scfd;
- Based on predicted El Niño patterns the next occurrence could be during 2014. LNG arrangements should be in place for this timing.

Translating the above into a requirement for gas/LNG gives the following summary from an infrastructure and LNG supply standpoint:-

<u>LNG requirements:-</u>

- An option to take delivery of LNG when needed;
- Option to take LNG to be exercised with approximately three months notice;
- Gas flow rate up to 400 million scfd which equates to approximately one cargo per week (standard sized LNG ship 125,000 – 145,000cm);
- Likely time for deliveries December to April with flexibility to shorten, extend or move;
- No requirement for a minimum volume (since there could be years where LNG is not required);
- Gas send out to match grid quality specifications.

<u>Infrastructure requirements:-</u>

- Ability to remain idle for potentially long periods (i.e. no requirement for cool-down, commissioning cargoes or maintenance of system pressures);
- Supply gas to high pressure grid (up to 100bar);
- Wide range of gas send out rates – zero to full flow (400 million scfd) depending on severity of gas shortage;
- Ideally no requirement for quality adaptation (nitrogen injection) – reduces costs;
- Minimal capital cost or minimal charter/option when the terminal is not in use.

4.2. Commercial infrastructure and LNG supply challenges for Colombia

4.2.1. Capital cost

The vast majority of LNG import schemes worldwide are designed for a base load application i.e. they are used all year around with relatively small seasonal variations in volume throughput. Continuous throughput results in the costs and commitments being spread throughout the year and, therefore, spread across all the LNG volumes imported. Some schemes (notably in South America) are designed for partial year use only – this has the net effect of pushing up the per unit energy cost for LNG delivered. For example, a terminal which works only half a year will have double the capital cost on a per million Btu basis as the same size (deliverability) of terminal with an all year requirement. It follows that for Colombia capital costs could be a challenge since LNG will not be required at all in some years. However, the capital costs (debt and equity financing) will still need to be covered even if no LNG flows.

4.2.2. FSRU infrastructure

FSRUs are now widely accepted as a viable and low cost alternative to full land based LNG import schemes. The period 2008-2010 in particular has seen a number of FSRU schemes built globally as described previously. This has had the effect of:

1) Making FSRUs a main focus for any party desiring to set up an LNG import scheme and
2) It has reduced the available pool of "spare" FSRUs and the pool of older ships suitable for FSRU conversion.

Today it is only Excelerate and GdFSuez that have FSRUs available for immediate use. Furthermore, according to South-Court's own market research, even these limited facilities could be allocated (and hence not available for use in Colombia) within the next 18 months. No doubt new FSRUs will be added to the world's fleet in due course but this will take time (2-3 years for a new build). In short, companies with FSRUs have a lot of options to place their vessels in today's market and are, in general, enjoying high demand for their services and equipment.

Companies with FSRUs would rather charter their equipment all year around ideally for a number of years as a full commitment – for example a 10 year charter with 5 year option. In particular, this applies to conversion of existing ships (where FSRU owner's would need to invest new cash to pay for the ship conversion). It follows that for any scheme which does not use the FSRU for significant periods it is highly unlikely that the FSRU provider would accept an off-hire provision at no cost. In other words the FSRU will still have to be essentially paid for all year around, every year even if not used. It may be possible to limit the "non-use" charter costs by negotiating some form of option payment or lower charter rate for non-use periods but even here the extent to which FSRU providers could or would accept such provisions is unknown. Certainly, the FSRU would need to cover its opportunity cost (i.e. the potential cost of not taking other more firm charter deals).

For the purposes of this study, it has been assumed that there is sufficient gas pipeline capacity in place and no additional pipelines would have to be built. Capacity in the pipelines (open access) is taken by the LDZ's (see Attachment 1 Glossary for definition) who move the gas from the supply point (fields) to the demand centres. The cost of the pipeline from the coast (near to the ports Santa

Puerto / Bolivar) is ~ $1.50/MMBtu set by a tariff established by CREG on a five year basis. In the case of LNG imports, inland power producers may not want to use gas from LNG, as it would cost them more to transport than using gas from the Cuisane field. They may also want to be excluded from any structural arrangement for providing LNG facilities and LNG imports during El Niño.

4.2.3. LNG Supply

LNG suppliers would rather have fixed longer term contracts (5 years+). Any supplier committing to provide LNG on a "as and when required" basis would need to add to the price, the opportunity cost of not taking other possibly more firm sales opportunities. It is also difficult for any LNG supplier to quote a pricing index which would reflect the real market price of LNG (and ships) when the LNG actually flows. It may be possible to negotiate an option cost, cancellation fee or other structure but these are extremely rare. It will certainly be possible however, to tender, source or negotiate with suppliers when the need is fully known. In the case of Colombia this could entail the sourcing of LNG three or four months prior to first delivery (this is the method used by some other part-year LNG buyers e.g. Brasil and Argentina). The only risk faced by the LNG buyer is the risk that the spot or flexible LNG would not be available when needed or that the price of spot LNG would be very high. However, the growth in LNG traded markets would indicate that LNG will indeed be available at a price (which is impossible to predict).

4.2.4. Summary assessment of commercial infrastructure options for Colombia

Sourcing LNG on a committed or option basis for Colombia could be a big hurdle. It is much more likely that LNG at acceptable prices will be easier to source on a "when needed" basis from the spot/flexible market. This type of purchasing policy is much better suited to an FSRU infrastructure scheme which can accept LNG delivery from standard LNG ships (e.g. FSRU turret on station or jetty based LNG delivery systems). In this way the potential LNG supply can be sourced from a much wider range of players when needed.

As above, FSRU owners will need to be paid (fixed or option) for their facilities more or less regardless of use, so it follows that there is a trade off to be optimised between capital commitments (i.e. cost of infrastructure) and the cost of FSRU options. In other words, it may make sense to build a more expensive import facility to reduce the cost of FSRU charter options or off-hire options (for example by building an FSU type scheme where the regasification is provided onshore or on-jetty).

Some options will give Colombia the greater flexibility to bring LNG into the country during non El Niño periods which will give the country greater flexibility and back-up in case of gas field maintenance or increased demand.

	Scheme	Configuration	Applicability to Colombia Score 1 (low) – 10 (High)
1	Land Based	LNG discharge jetty Onshore tanks (with total storage approx. 200,000m^3) Onshore regasification	SCORE 1 - LOW Due to the optional nature of LNG demand, building a land based facility for use, say, once every five years is not economic. Also, if new gas reserves are found the facility will remain unused.
2	FSRU with offshore single turret	Single offshore buoy LNG is stored and regasified on the vessel and supplied to market via the single turret	SCORE 3 – LOW During periods of El Niño, Colombia will require gas supply from LNG on a consistent basis with no breaks. With this option there would be 6-12 hour breaks as vessels move on and off the delivery turret. Also, this option would require the availability of two FSRUs vessels and may limit LNG supply options.
3	FSRU with offshore single turret and ship-to-ship LNG transfer from the "delivery" vessel to the FSRU	Single offshore buoy with standard LNG ships delivering to the FSRU ship-to-ship. The FSRU stores the LNG and regasifies the LNG and sends gas to market via the single turret	SCORE 7 – MEDIUM/HIGH This option enables consistent supply to Colombia during El Niño. LNG supply options may be limited, as this option requires offshore ship-to-ship transfer, which some of the LNG delivery ship owners may be reluctant to do on a regular basis. Such a facility would require benign sea conditions.
4	FSRU with twin offshore turret	Twin offshore buoys. FSRU attaches to the turret, LNG is stored and regasified on the vessel and supplied to market via the single turret	SCORE 7 – MEDIUM/HIGH Two-buoy delivery ensures consistent supply of gas to Colombia during El Niño. This option would require the availability of two FSRUs vessels and may limit LNG supply options.
5	FSRU jetty	Single jetty head with gas discharge. FSRU brings the LNG to the jetty and LNG is stored and regasified on the FSRU and supplied to market via high-pressure pipe.	SCORE 3 – LOW During periods of El Niño Colombia will require gas supply from LNG to be consistent with no breaks. With this option there would be 6-12 hour breaks as vessels move on and off the delivery jetty. This option would require the availability of an FSRU vessel and may limit LNG supply options
6	FSRU jetty with FSRU on station	Single jetty head with gas discharge and LNG transfer lines. Standard LNG vessel brings the LNG to the	SCORE 8 – HIGH This option would enable gas to be supplied on a reliable basis during El Niño. This option relies on an FSRU vessel being available when required by Colombia (this would be achieved through having an option agreement with an infrastructure/vessel provider)

		jetty. The LNG is then transferred to an FSRU. LNG is stored and regasified on the FSRU and supplied to market via high-pressure pipe.	
7	FSU jetty with FSU on station	Single jetty head with onshore regas and LNG transfer lines. Standard LNG vessel brings the LNG to the jetty that is transferred to an FSU. LNG is stored on the FSU, regasified using onshore regasification facilities and supplied to market via high-pressure pipe.	SCORE 9 – HIGH This option would enable gas to be supplied on a reliable basis during El Niño. It also would not rely on an FSRU vessel being available/on call as the regasification facilities will be available on the jetty/land. The use of standard LNG ships would widen the choice of vessel options and LNG sources available to Colombia.
8	Regas jetty with no FSU	Single jetty head with onshore regas and LNG transfer lines. Standard LNG vessel brings the LNG to the jetty and is slowly discharged to the regas system. Delivering ship stays on jetty throughout (7 days+).	SCORE 9 – HIGH This option is the lowest cost, but would require the LNG delivery vessel to remain on station while LNG is supplied to the jetty/land based regasifiers and gas supplied to the market.

The chart below plots the different infrastructure schemes, cost (from the table in section 3.3) and the "applicability score" set out in the table above. Those schemes in the top half of the table have a high applicability but at varying costs, those in the bottom are less applicable for Colombia.

It is difficult to define exactly the costs for each scheme without a full technical feasibility study, but roughly, the infrastructure and option costs cost over 10 years (MOD), would be in the range:

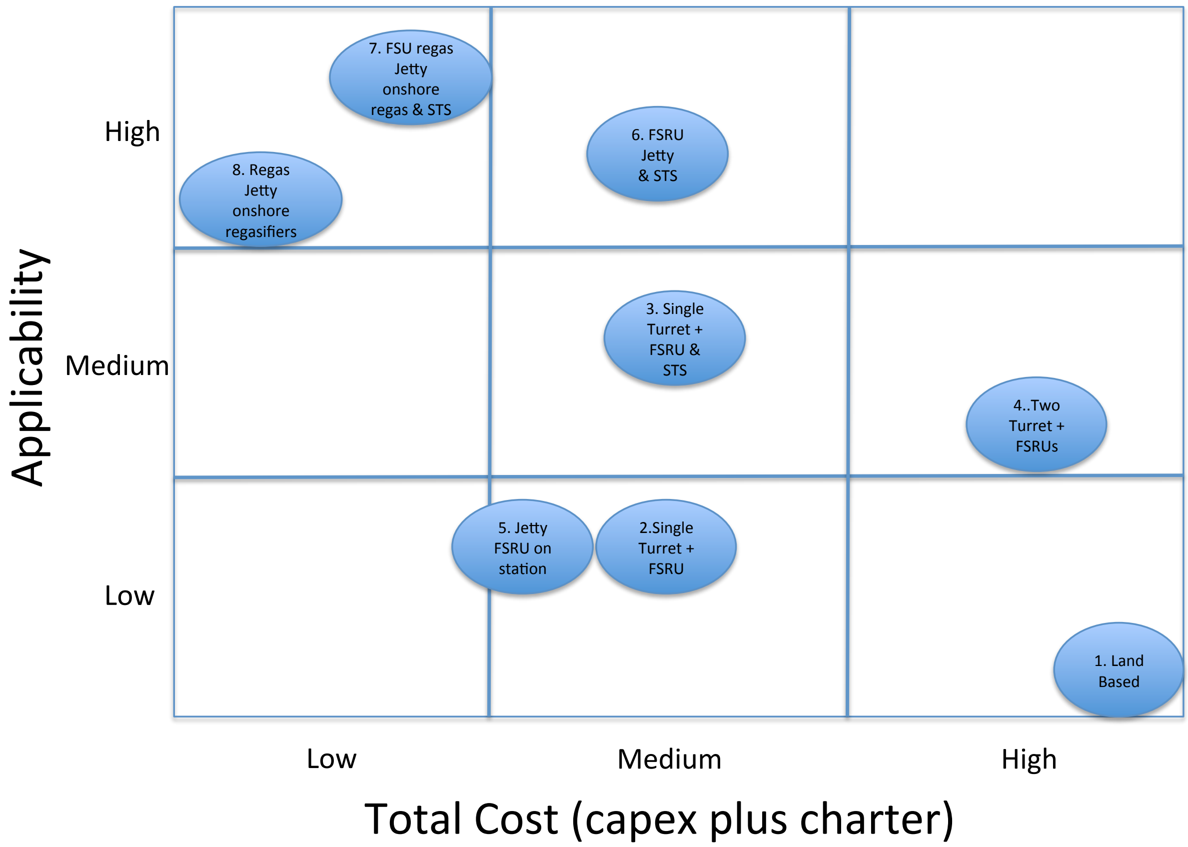
Low: US$ 0-250 million
Medium: US$ 250-750 million
High: US$ 750-1000 million

In addition all costs of sourcing LNG and operating costs would have to be added.

The conclusion of the analysis is that a land based regasification terminal would be the most expensive and not be applicable to Colombia, as the plant would remain unutilised for most of the time. Also, if Colombia were to find additional gas reserves, then the facility would not be required after ten years.

The offshore turret schemes vary in cost depending on whether one or two turrets are used and whether an FSRU is located on the turret at all times during El Niño or whether one FSRU is used, with corresponding breaks on gas supply when the vessel is empty and goes off station. Where the proposed scheme results in a break on gas supply then it scores low on applicability.

The jetty schemes likewise depend on whether there is a FSRU or FSU permanently on jetty during El Niño, or if there is a break in supply (break in gas supply means low applicability score).



There are two high scoring lower cost schemes – both using low-cost onshore regasification facilities located on the jetty or on land. The exact cost of these options will depend on the exact technical solution for the location, but it can be assumed that a jetty mounted regasification facilities could have lower costs as they would have the shortest amount of costly cryogenic LNG pipelines. In the case of options 7 & 8 there would have to be regular maintenance during period that they are not being used (i.e. outside El Niño), but the facilities would also enable imports of LNG outside of El Niño if required.

The main reason why schemes 7 & 8 have lower costs is that they would not rely on FSRUs, which the other schemes do (except scheme 1). At current time, FSRU operators are seeking premium rates for their vessels and would charge high option costs to guarantee the availability of the vessel when required. The exact amount that companies would charge can only be accurately ascertained by approaching them with a firm requirement, but the calculations based in this report have been based on initial informal approaches.

4.2.5. LNG Supply options for Colombia.

Given the 2014 start-up requirement for LNG imports to Colombia, LNG will need to be sourced from LNG export facilities that are already in operation or are in the final stages of construction. Other proposed LNG export projects (for example Nigeria Brass, Nigeria T7, Nigeria OK LNG, Egypt Damietta T2, US Sabine Pass export, US Freeport export) will not be in operation in time for Colombia start-up in 2014 although these new export facilities, if and when constructed, can be considered as supply options for Colombia in later years depending on circumstances at the time.

A number of factors have combined in recent years to make the LNG sourcing picture somewhat confused and difficult to predict. As follows:-

- Currently high oil prices have tended to favour Asian buyers (who can buy LNG with oil linked prices). Hence, suppliers are more keen to sign spot, medium and long term deals into Asian markets rather than the US or Europe;
- US shale gas has depressed US gas pricing now and also in the longer term. This tends to drive LNG volumes away from the US and towards Europe or Asia;
- The two factors above have resulted in significant volumes which were originally intended for the US being diverted to Asian markets (most notably Qatari volumes);
- The entrance of many new LNG trading players has increased competition for spot and medium term cargoes but has also increase the range of companies who may be willing to supply short term deals;
- The currently tight shipping market is hampering the flow of traded spot/medium term deals;
- The Japan tsunami in March 2011 increased Japanese LNG demand in the short term. The longer term effects of a potential global downturn in nuclear power are yet to be fully understood, but it is likely that Japan will increase its demand for LNG for power generation with a reduction in nuclear power generation;
- In theory the LNG markets are currently supply long (i.e. more LNG supply than LNG buyers). Industry opinion varies widely as to the duration of any supply overhang but it now seems likely that the growth of LNG in China and uncertainties re nuclear power have brought the supply/demand situation into better balance i.e. there may not, in practice, be a supply overhang at all.

Whilst, in theory, LNG for Colombia could originate from anywhere in the world its likely that LNG would, in practice, be sourced in the Atlantic or from Middle Eastern LNG players who are active in the Atlantic.

In the Atlantic basin this includes the facilities of:-

- Trinidad and Tobago – Atlantic LNG (15mta);
- Nigeria – Nigeria LNG (22.2 mtpa);
- Algeria – Arzew, including Gassi Touil (22 mtpa) and Skikda (7.8 mtpa);
- Equatorial Guinea - EG1 (3.4 mtpa);
- Egypt - Idku (7.2 mtpa) and Damietta (4.8 mtpa);
- Norway – Snohvit (4.1mtpa);
- Angola – Soyo (5.2 mtpa).

All of the above facilities are in operation apart from; Algeria - Arzew GL3Z (4.7 mtpa start up 2012), Algeria - Skikda rebuild (4.5 mtpa, start up 2013) and Angola LNG (5.2 mtpa, start up 2012).

Some Middle Eastern LNG suppliers have also been active since the mid 2000's in respect of LNG sales into the Atlantic:-

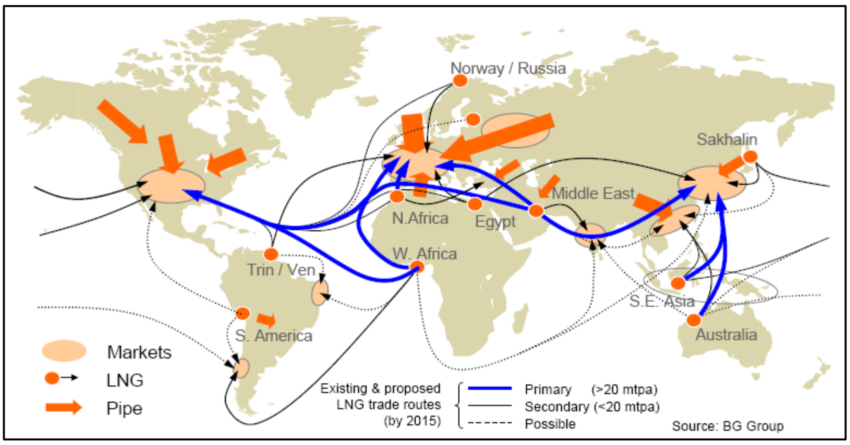
- Qatar - QatarGas and RasGas (77 mtpa combined);
- Oman – Oman LNG (7.3 mtpa) and Qalhat (3.7 mtpa);
- Yemen - Yemen LNG (6.7mtpa).

The majority of the LNG volumes noted above are not available as flexible or spot LNG. Most is already allocated to long term buyers (particularly Asian) where either diversions to alternative markets are not economically attractive or where the volumes are locked-in with firm delivery commitments to final customers with real markets. The volumes of LNG actually available to fill a new commitment (for example to Colombia) need to ascertained once the actual LNG need, conditions (e.g. price) and timing is known.

As regards approaches to the markets to source LNG - it is not always the source LNG export plant that would control the ability to sign new ex-ship deals. For example, most volume is controlled (i.e. already bought) by the International Oil Companies (IOCs), in particular Shell, Exxon, BG Group, GdFSuez, ChevronTexaco, Total, ConocoPhillips, BP and others.

It is not the intent of this document to exactly formulate and prescribe an LNG sourcing strategy for Colombia and, even if this were attempted, the recommendations would be short lived since deals which could be signed now, may not be available in a few months time. In addition, the choice of LNG sourcing strategy (source medium term or source on spot) will have a direct impact on the types of and number of companies approached. What can be ascertained at this stage however, is the following:-

- Global uncertainties have focused LNG seller attention towards Asia and away from the Atlantic;
- Sellers prefer to sell using oil indexation (although other forms of indexation are often agreed);
- The shipping market is tight and could remain so over the next few years;
- Signing a medium term deal for LNG purchase without exactly knowing the volume, timing or indeed if needed at all will either be expensive or will result in some form of option/capacity payment;
- LNG volumes sourced on spot will likely be available but the pricing is uncertain;
- Trading of LNG will remain increasingly global.



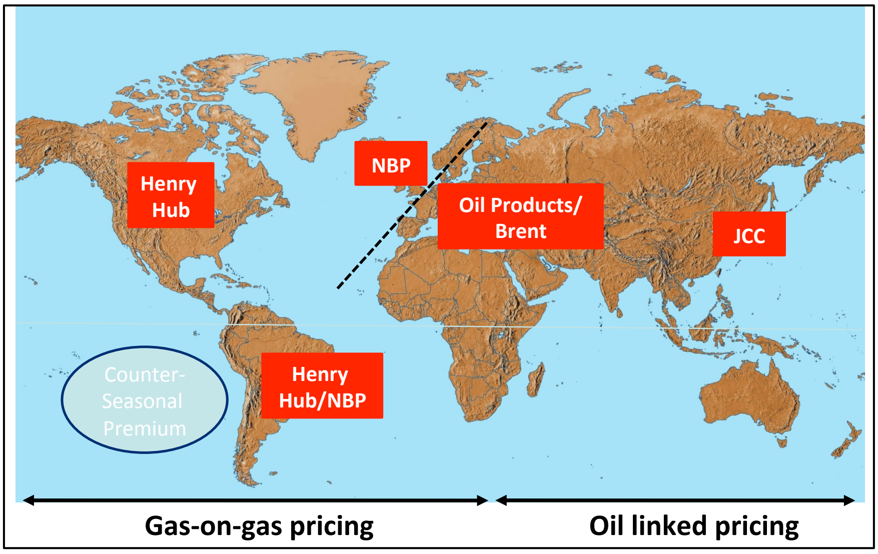
Source: BG

4.3. LNG Price – the basics

Pricing for LNG is often misunderstood. Therefore prior to analysing potential LNG price outcomes for Colombia its appropriate to clarify a few basic parameters.

There is no market price for LNG - LNG is not traded as a liquid commodity in the same was as oil, oil products, power, gas in pipeline grids etc. LNG prices are almost always set as between the buyer and seller (bilateral) via bespoke, confidential and binding contracts. In other words, there is no "market price" for LNG, no traded platform for LNG trades, OTC, exchange based or otherwise. There are, however, general indications of the types of price levels which are in discussion or have been concluded in recently signed deals. Platts, for example, publishes its JKM (Japan Korea Marker) index which reports spot price levels in Asia based on signed deals. JKM is not a bid/ask price – it is a record of recent deals and does not mean that LNG is available at that price today. The relatively small number of spot trades also means that spot prices are highly influenced by the latest deal done.

Long term LNG pricing – long term pricing has traditionally been linked to crude oil in countries where there is no gas-on-gas competition (so called "Firm" markets compared to "Flexible" markets where the gas price is set by a gas market price). For example in Asia, the Japan Customs Cleared Price (JCC or Japanese Crude Cocktail - which is an average price for all crudes imported into Japan for a month), is used and in Europe Brent or other oil indices. In Northern Europe and USA, gas market indices are used to determine the price of gas and therefore the price at which long-term, LNG cargoes can be purchased.



Source: South-Court Ltd

Under oil related contracts, the pricing formula ex-ship normally takes the form of; (Slope x oil) + Constant. The slope has traditionally been in the region of 14.85 with the Constant taken as a proxy for shipping costs and set in a range of $0.50 - 1.00/MMBtu. Hence, a traditional Asian supply deal with a Slope of 14.85[10] and constant $0.50/MMBtu would give an LNG exship price of $3.97/MMbtu at a JCC price of $20/bbl. The contracts also traditionally contained an S curve and S curve shoulders

[10] A slope of 17.2 with zero constant is often quoted as being oil parity (depending on oil quality) – i.e. on a per energy unit price basis at slope 17.2 the LNG price equals the oil price.

such that oil prices below $11/bbl or higher than $26/bbl would flatten the slope and provide the buyer with a degree of protection from high LNG prices at a time of high oil price. The S curve also provided the seller an LNG price benefit in the event of low oil prices. These types of pricing arrangements backed by long term (20 year) take or pay and send or pay obligations formed the bedrock of the LNG industry since its inception.

The situation changed post 2000 with new LNG supply projects competing for market. The pricing structure also changed when pricing went about $26/bbl in 2003. Long term contracts signed since 2000 have seen slopes as low as 5, or as high as 16.2 often with no S curve and have in general been far more influenced by the market power (supply/demand balance) in place at the time of the contract negotiation.

Similar oil price formulations (but set around a starting price – the so called P_0) where also a feature of long term deals into Europe although these deals could also include reference to oil products, Consumer Price Indices, other energy price markers or a basket of different indices. Medium or long term deals signed in the Atlantic since 2000 have often included reference to US or European gas hub pricing Henry Hub, NBP or TTF.

Spot LNG price - Since the spot (or single cargo price) is derived from LNG that has already been sold (i.e. is already included within the economics of an operational LNG chain), then in theory the spot price can be anything as decided between buyer and seller – fixed, oil linked, Henry Hub (USA), NBP (UK), TTF[11] (Netherlands) or a mix of indices.   Henry Hub and NBP have even been used to set spot levels into Asia since the driver to capture spot is to offer a slightly higher price than the seller's next best price alternative. For example throughout 2010 the spot price in Asia was broadly set via reference to NBP plus shipping costs (NBP being the price to beat) as NBP was the next best price offered after Asian prices. Medium term deals are a mixture of both long term and spot pricing influences. Brasil and Argentina have been buying LNG on the basis of attracting the cargo away from the highest alternative market, be it Asia, Europe or USA. So these countries have been buying cargoes on NBP and Henry Hub related prices plus freight differentials.

4.4. LNG Pricing for Colombia

As discussed previously the range of LNG prices available for Colombia will depend entirely on the sourcing strategy employed. Medium/long term or Spot i.e. supplier committed volume (in this case with the addition of a buyer option) or source the LNG when needed at the time.

4.4.1. Medium term price drivers

Based on market conditions today (April 2011) LNG suppliers would be unlikely to base a medium term deal on Henry Hub type pricing. Henry Hub prices in recent years have fallen dramatically since the advent of shale gas discoveries. Industry observers believe that US gas (Henry Hub) prices will stay in the $4-6/MMBtu price range since this is approximately the marginal cost of new shale gas production. The Japanese tsunami has also prompted suppliers to keep their options open in the expectation of further oil related sales in Asia.

[11] TTF = Netherlands virtual gas hub "Title Transfer Facility"

NBP would be more attractive for suppliers since industry projections of European hub pricing (NBP and TTF) are significantly higher than Henry Hub (NBP/TTF has been approximately double the Henry Hub price over the past few months). Also the basic drivers of price are quite different in Europe as compared to the US. For example, European gas production is in decline, security of supply issues are still a concern and Russian gas suppliers are reluctant to sell pipeline gas using European hub pricing etc.

An oil price formula would be the most attractive for a supplier since most suppliers are already diverting quantities to Asia to sell using oil slope type indices. Possibly a mix of oil and higher of Henry Hub/NBP would be attractive although it is impossible to predict until the negotiations start.

In discussions with potential LNG suppliers about selling LNG to a market such as Colombia where the buyer seeks as "option" to buy, companies have said that they may be willing to commit volume but not price. Indeed, LNG sellers are not even willing to commit to a pricing basis (i.e. oil, Henry Hub or NBP related) at this time where cargoes may not be taken if not required. The clear message is that the price will have to be agreed at the time the option is declared i.e. in the August/September prior to the winter demand period.

4.5. LNG Quality

Colombian gas quality is governed by CREG which sets the specification limits for gas entering the pipeline system. CREG 071, 1999 (as amended 2007) sets the range of specifications for gas entering the system as below. Of particular importance for LNG imports is the Gross Heating Value (GHV) range with is set for Colombia as between 950 – 1150 Btu/cf.

Especificaciones	***Sistema Internacional***	***Sistema Inglés***
Máximo poder calorífico bruto (GHV)	42.8 MJ/m^3	1.150 BTU/ft^3
Mínimo poder calorífico bruto (GHV)	35.4 MJ/m^3	950 BTU/ft^3
Contenido de Líquido	Libre de líquidos	Libre de líquidos
Contenido total de H_2S máximo	6 mg/m^3	0.25 grano/100PCS
Contenido total de azufre máximo	23 mg/m^3	1.0 grano/100PCS
Contenido CO_2, máximo en % volumen	2%	2%
Contenido de N_2, máximo en % volumen	3	3
Contenido de inertes máximo en % volumen	5%	5%
Contenido de oxígeno máximo en % volume	0.1%	0.1%
Contenido máximo de vapor de agua	97 mg/m^3	6.0 Lb/MPCS
Temperatura de entrega máximo	49 °C	120°F
Temperatura de entrega mínimo	7.2 °C	45 °F
Contenido máximo de polvos y material en suspensión	1.6 mg/m^3	0.7 grano/1000 pc

Source: CREG

LNG quality specifications vary across the world's LNG export facilities. In general plants located in the Atlantic tend to produce LNG of lower GHV than plants in Asia or the Middle East as the market demand is for lower GHV gas. The quality of LNG produced can also vary over time or vary with seasonal conditions (LNG export sales contracts therefore include a band or range of acceptable specifications). The detailed information is normally confidential and is provided by the LNG supplier only once an LNG supply transaction is in discussion. However, sample data sources can give a good indication of the approximate quality of LNG produced. It should be noted that the GHV of the LNG increases (enrichment) as it is transported in LNG ships since the lighter components and nitrogen will boil off first leaving a slightly enriched LNG in the ship's tanks. The effect is relatively small at 0.5 – 1.0 Btu/scf increase per day of sailing. Even such a small effect, however, could potentially lead to quality issues for deliveries ex-ship to Colombia from Middle Eastern, Angolan or Nigerian facilities since LNG from these facilities have GHVs close to the Colombian high end limit.

LNG Quality Specifications by supply source (Btu/Scf)	
Atlantic LNG, Trinidad and Tobago	1031
Egypt Damietta	1040
Egypt Idku	1040
Algeria	1058
Algeria GL37	1070
Equatorial Guinea	1075
Snohvit, Norway	1075
Yemen LNG	1075
Oman & Qalhat LNG	1100
Nigeria LNG	1114
Angola LNG	1115
QatarGas	1124
Source: Woodmac, 2007	

Initial research shows that it does not appear that there will be significant restrictions on the import of LNG from a quality perspective into Colombia although the GHV high limit could be an issue for some supplies at the top end of the ranges as above. Hence, there should be no need for nitrogen injection or other quality adaptation methods to be employed in Colombia at the LNG receiving location. However, once LNG supply discussions start then the contractual limits (high and low) for each component of LNG quality (including Gross Heating Value, hydrocarbon due point etc.) should be checked fully against the applicable Colombian gas entry specifications in force at the time.

4.6. LNG imports into Colombia - possible commercial and business structures

Irrespective of the LNG supply strategy adopted, to successfully import LNG into Colombia there will need to be a structure that includes:-

1) Buyer for the LNG (the "*Buyer*"),
2) Owner/financier of the import terminal ("*Terminal Owner*") and
3) A party to own the terminal capacity rights ("*Capacity Holder*").

A connecting gas pipeline is, of course ,also required to join the terminal to the pipeline grid although here parties outside of Colombia will be very reluctant to invest or take ownership. It is, therefore, assumed in this document that Colombian pipeline company(s) will handle the permitting, construction, ownership and operation of the pipeline up to the gas send out flange of the import terminal.

As regards LNG business structures globally, there is no single answer to the question "how should Buyer, Terminal Owner and Capacity Holder organise themselves". In other words, there is no worldwide adopted standard arrangement and instead the structures selected in different parts of the world are bespoke and particular to that application. The business structures adopted are driven by a number of factors:-

- The requirements of in-country procurement laws (e.g. requirement for tenders);

- Local content requirements (which could include a legal requirement for local ownership or local ownership of a certain percentage in the proposed entities);
- The technical and commercial capabilities of in country incumbents;
- The financial strength of in-country incumbents to raise debt to fund terminal construction and/or in particular to enter into guarantees for LNG supply obligations;
- Political desirability of one structure over another;
- Other, many and varied regional or in country requirements.

A key question is whether Colombia will need to sign a medium/long-term arrangement for LNG supply in order to ensure that it gets LNG when it needs it. In discussions with several LNG suppliers, they advise that as Colombia wants the right to take or not to take the LNG, depending on whether El Niño is effecting rainfall, it would be difficult to agree a price for optional supply of LNG over a ten year period. Volume could be committed, subject to a price being agreed. This effectively means that if the supplier does not want to supply it need not agree a price. As such, it may be necessary for Colombia to rely on the short-term market for its supply – issuing a tender in September for supply from December that year. This is what Argentina and Brasil are already doing (see section 3.2.3). Whichever structure Colombia develops (i.e. buying term with a price negotiation or buying spot/short-term at the time the LNG is required). If Colombia is willing to pay a high enough price, higher than the alternative market or buyer, then it will be able to secure the necessary LNG. It is important that LNG suppliers are aware of Colombia as a potential LNG buyer and that its LNG importation facilities meet industry requirements and are acceptable to LNG sellers. Colombia would therefore have to appraise LNG suppliers of their facilities once there are in operation and ahead of seeking LNG cargoes.

5. Commercial Structures for Colombia

5.1. Elements of a commercial structure

In examining a possible commercial structure for Colombian LNG imports, it is necessary to examine the different elements of the gas chain within Colombia as set out in the diagram below. One lesson from many LNG projects is the simpler the project structure the easier it is to develop as it prevents conflicts between different parties and gives clear direction and ownership to the development of a project.

A key factor driving the commercial structure is that Colombia only needs the LNG during the period of El Niño and this occurs, on average, once every five years. It is required, therefore, that the necessary infrastructure be in place by December 2014. It is expected that Colombia will know whether El Niño will affect rainfall in August each year. If yes then, by 1st September each year, Colombia will want to declare its option to have the infrastructure in place[12]. At that time, Colombia will also declare its option for LNG supply (if such an option can be secured) or issue a tender to the spot/short-term LNG market.

The different elements of the project structure are:

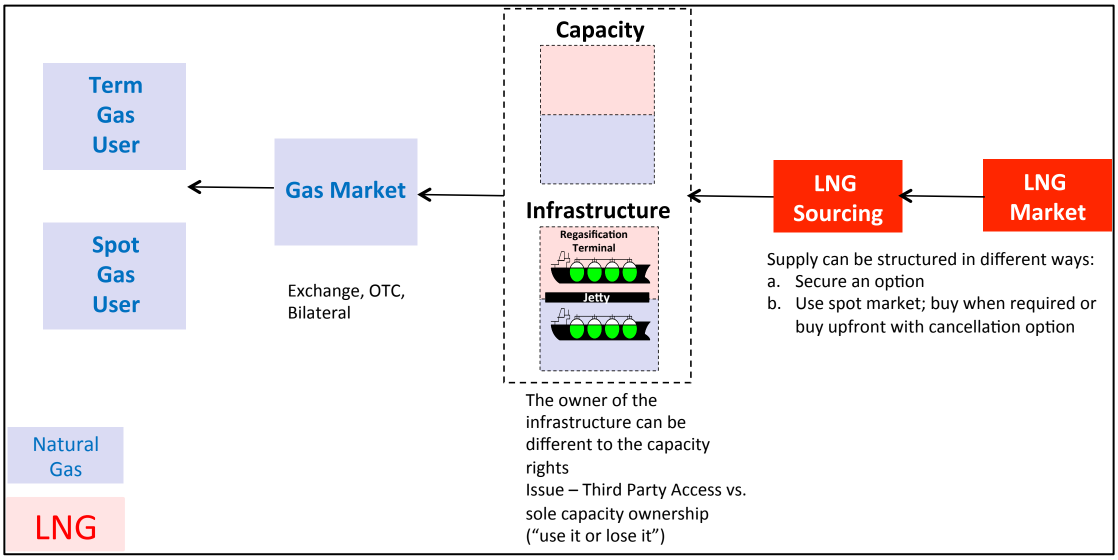
a) **LNG Sourcing** – LNG supply can be structured under a long-term arrangement or through buying from the spot/short-term market as required. As noted in section 4.10 it will be

[12] In the case of Option 8 in section 4.5 no option for infrastructure is required.

difficult to secure long-term LNG volume, with an agreed price, with the option mechanism that Colombia requires. That said, Colombia can secure the LNG if they pay a market competitive price.

b) **Regasification capacity** – The owner of the infrastructure can be different from the company that owns the regasification capacity rights. Where the owner of the capacity and the owner of the infrastructure are different, it is the credit of the capacity holder and its capacity payments that underpins the development of the regasification infrastructure. The company that develops the infrastructure and enters into commercial arrangements for the regasification facilities is key to the delivery of the project.

Attention must be drawn to third party access rights, which regulators define to ensure that the capacity does not get "hoarded" to prevent third parties from access.[13] CREG may wish to consider how third party access arrangements are structured during the period of El Niño and when outside this period. The arrangements could be different outside El Niño when, if third party companies want to bring LNG into the country through the facility, it could be permitted, with an agreed tariff.



Gas Market – Gas can be sold into the gas market through and exchange or on a bilateral basis. Gas can then be sold to term gas buyers or on a spot basis.

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[13] Some countries (inc. the UK and European Union) regulations require that all LNG terminals offer third party access. New terminals and expansions, however, seek and are usually given, exemption from this open market requirement. This exemption is given on the condition that the terminal operators make available any unused capacity to third parties. This requirement is commonly called the Use it or Lose it (UIOLI) provision. This requirement should, in theory, enable additional LNG cargoes to enter the UK, if the existing capacity holders do not want to use the capacity.

The issue is that the times when the capacity holders do not want to use their capacity are likely to be during periods when the domestic gas price is low vs. other LNG markets. This is the same time that other companies would not want to bring cargoes into the UK market. If gas prices are high in the UK (when other companies want regasification capacity to import LNG cargoes), then the capacity holders will most likely want to use their own capacity and not make it available to other companies.

The regasification infrastructure will be paid for by the party that holds capacity and has the right to use it. The cost of this will vary depending on the capital cost involved, but would normally be structured as:

1. Capacity payment – to cover the capital cost of the facility. In the case of Colombia, this would include any option payments for a regasification vessel that may be agreed.
2. Throughput fees – to cover operational costs in the regasification facility. In the case of Colombia, there may be different fees depending on whether the facility is being used or is not (as there could be long periods when the facility remains unused).

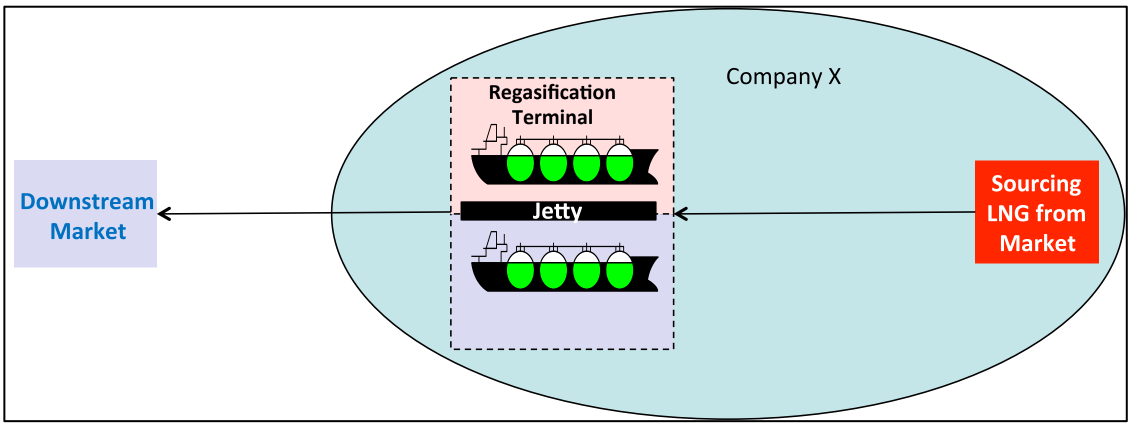
5.2. Domestic Structures

The structures set out below assume private investor involvement in each stage of the chain. The type of investor will depend on each model and what is required by that company.

A key premis driving all structures is that the buyer of LNG must be a company with at least an A+ credit rating and it must be able to put in place the necessary financial guarantees for the purchase of LNG. Though the amount of such guarantees is not clear, its should be assumed that LNG sellers will seek a parent company guarantee (from a suitable AA or AAA credit rated company) or a letter of credit covering several hundred million US dollars. A stand-bye letter of credit, in the case of a financially secure company, may also be acceptable.

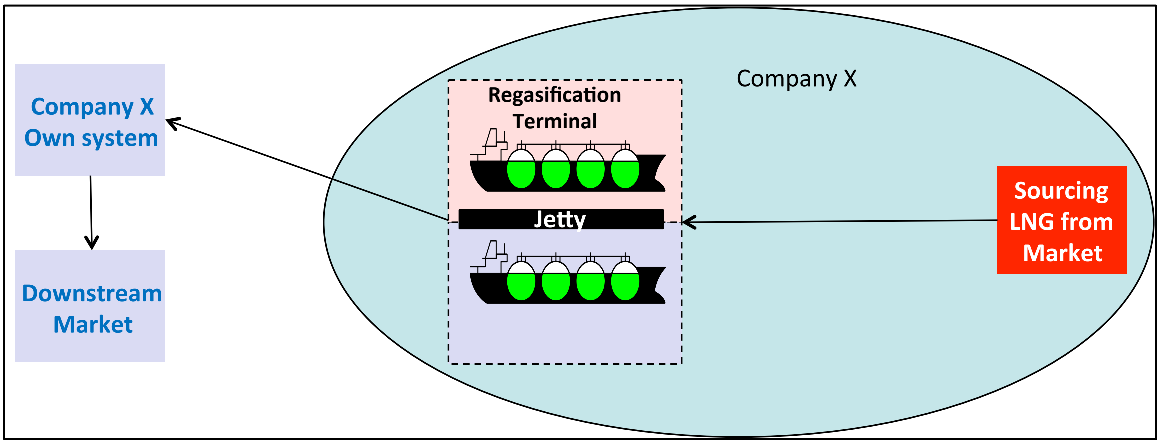
5.2.1. Model 1a - The same company buys the LNG, owns regasification facilities & capacity and sells to the market

Under this structure, one company (Company X) buys the LNG from the market, owns the regasification infrastructure and capacity, and sells the gas to the downstream market. This could be an independent company or a company from within the chain itself. This is a simple model with one company managing the whole development of the infrastructure, LNG sourcing, regasification and selling to market.



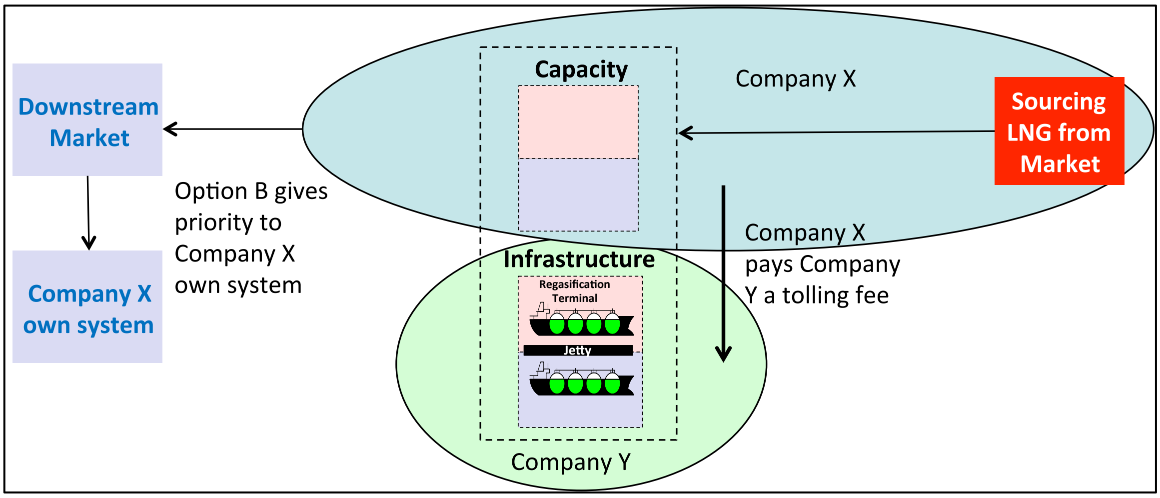
5.2.2. Model 1b - The same company buys the LNG, owns regasification facilities & capacity and sells gas to the market

Under this structure, one company (Company X) buys the LNG from the market, owns the regasification infrastructure and capacity, and sells the gas to the downstream market. The difference to model 1a is that the gas is sold to Company X's own system in priority to the market. Only surplus gas, over and above Company X's own requirements, are sold to third parties. Under this model,. Company X would be a gas user who is effectively sourcing gas for its own system.



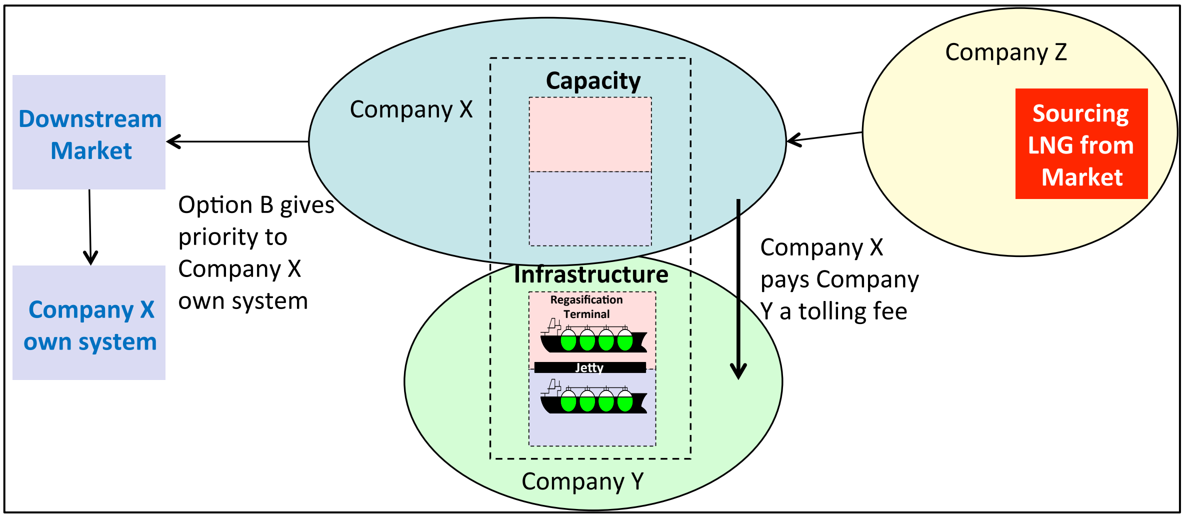
5.2.3. Model 2 - One company owns the regasification facility, a second buys the LNG, and pays a fee to toll through the regasification facility and sells gas to market

Under this model, the regasification terminal is owned and operated by one company (Company Y). This company sells commercial capacity in the terminal on a long-term (10 years) basis to capacity users. In this example, it is assumed that Company X takes the capacity, but it could be several companies. The reason one company is assumed, is that it may be best, due to Colombia's intermittent requirement for LNG, for one company to access the LNG market. Under this model, Company X sells gas to the market and as with the previous model, this could take the structure of all gas being sold to the open market, or first to Company X's (or several companies if more than one company is using the regasification capacity) system, with the balance supplied to the market.



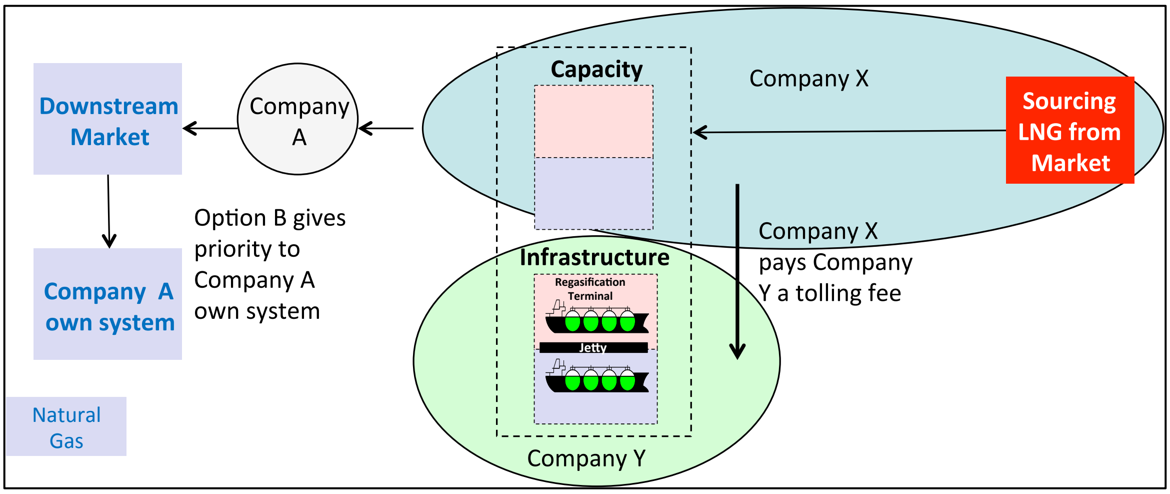
5.2.4. Model 3 - One company owns the regasification facility, a second buys the LNG and sells it to Company Z who pays a fee to toll through the regasification facility and sells gas to market

This model is the same as model 2 except LNG is sourced from the international market by a third company (Company Z) who sells it to Company X (or different companies in the case that there are more than one) who pays Company Y a tolling fee. This structure would enable an international company, specialist in LNG, to source the LNG on behalf of the domestic Colombian users, while leaving the domestic business to Colombian companies. Company Z, the organisation that sources the LNG, could be an international LNG company.



5.2.5. Model 4 - One company owns the regasification facility; a second buys the LNG, and pays a fee to toll through the regasification facility. The gas ex-terminal is sold to a third company, who sells it to the market

This model is similar to model 2 except, that the gas ex-terminal is sold to a third party gas marketing company (Company A) who sells it to the market (through an exchange or bilateral arrangement). By doing this, the LNG supply and regasification is separated from the market and it could enable increased competition with different companies being able to buy gas from the gas marketing company. This does add an additional link in the gas supply chain, with its complexities, but could give greater access to gas from LNG, particularly for the smaller gas buyers. In a separate option (s with the other models, Company A could sell the gas to its own system in priority to the rest of the market.



5.2.6. Summary of commercial models, advantages and disadvantages of each model

The table below sets out the advantages and disadvantages of each model:

	Structure	Advantages	Disadvantages
1a	Same company buys LNG, owns regasification facilities & Capacity and sells to market	• Simple • One company controls the development of the project • One company sources the LNG and operates the terminal making the operations of the terminal easier than multi-user terminals	• One company could mean reduced competition in the market and only one company gains LNG expertise • One company sourcing the LNG would need to have LNG knowledge, otherwise it may not cover the full market • Priority to Company X's own system may limit gas availability during periods of gas shortage
1b	Same company buys LNG, owns regasification facilities & Capacity and sells to its own system and with any surplus gas sold to the market	• Same as 1a • Would ensure that surplus gas reaches the market	• If Company X is forced to supply a specific volume of gas to the market, instead of its own system, then it may not have the incentive to develop the project quickly
2	One company owns the regasification facility, a second buys the LNG, and pays a fee to toll through the regasification facility	• A separate company owning the regasification infrastructure means that a specific infrastructure specialist could develop the capacity, underpinned by long-term capacity agreements • The option enables several companies to individually	• The involvement of more companies means more complexity (how is the tolling fee set? Do all companies pay the same?) • In the case of several companies taking regasification capacity, it means that several companies will be sourcing

		take capacity in the facility • May provide more competition and open up the facility to other companies outside of El Niño	LNG from the market, adding internal competition to the global LNG market • Higher operational challenges
3	One company owns the regasification facility, a second buys the LNG and sells it to Company Z who pays a fee to toll through the regasification facility and sells gas to market	• One company sourcing LNG would enable expertise to be developed • This structure would enable several companies to take capacity in the regasification terminal while not diluting the need to source LNG as one • Could result in additional competition	• Same as option 2 • Using a separate company to source LNG adds complexity to the structure, as additional contracts will be required with clear flow-through of obligations.
4	One company owns the regasification facility; a second buys the LNG, and pays a fee to toll through the regasification facility. The gas ex-terminal is sold to a third company, who sells it to the market	• Gives smaller companies access to gas from LNG • Enables the gas reseller to easily sell gas through an exchange • Company A focuses on the domestic market while Companies X & Y focus on LNG.	• Adds another link in the chain, therefore more complexity • Company A could sell all the gas to its own system thus reducing competition • Divorces the cost of gas from LNG from the end user

There is no one structure that can be clearly identified as the best one for Colombia. The final structure will depend on local requirements and company interests. As noted above, there are two key drivers that must be taken into consideration:

1. The simpler the better – developing infrastructure projects is a costly and complex undertaking. The more companies involved the longer it takes to develop such projects. Also, the right companies must be involved. Selection of companies and partners for political means can often result in the wrong companies (with the wrong skills) being involved which results in the slowing down of a project.
2. The structure must be credible to LNG infrastructure providers and LNG sellers. If not, then it may be difficult to secure the necessary LNG supply.

Attachment 1

Glossary

Aggregator	A company who purchases LNG from several sources and supplies LNG to several buyers and uses its LNG portfolio to its commercial advantage
Arbitrage	Where a cargo is moved from one trading region or country in order to enjoy an upside financial gain
Billion (or bn.)	1,000,000,000
BCMA	Billion Cubic Metres per annum
EPC	Engineering Procurement Contractor (constructs the LNG plant)
Export Credit Agency	Export Credit Agencies are government-funded bodies that advance funds and provide risk cover in return for selling their countries goods and services (e.g. US Exim, Japan Exim, SACE, Italy)
Ex-ship	An LNG cargo is sold "ex-ship" where the seller arranges the shipping and title and risk passes from the LNG seller to the buyer at the discharge port
Final Investment Date (FID)	The date on which the project sponsors decide to make a financial investment decision to move ahead with a project. This decision is usually made in parallel with awarding the plant engineering, gas purchase and LNG sales contracts
FOB	Free on board - an LNG cargo is sold "FOB" where the buyer arranges the shipping and title and risk passes from the LNG seller to the buyer at the load port
FPSO	Floating production, storage and offloading unit is a floating vessel used by the offshore oil industry for the processing of hydrocarbons and for storage of oil. A FPSO vessel is designed to receive hydrocarbons produced from nearby platforms or subsea template, process them, and store oil until it can be offloaded onto a tanker or transported through a pipeline.
FSRU	Floating storage and regasification unit; a vessel with LNG regasification facilities on-board that can regasify LNG and supply gas direct to market
FSU	Floating Storage Unit - an LNG vessel that is used for storing LNG at a regasification terminal in place of having shore LNG storage tanks. This vessel does not have regasification facilities on board.
IOC	International Energy (Oil) Company
JCC	Japanese custom cleared crude price or Japan Crude Cocktail, the average price of crude oil imported into Japan in a given month
LDZ	Local Distribution Zone is a geographic area supplied by one or more gas distribution system pipeline networks
Markets	The markets of North America and Northern Europe have alternative sources of gas, domestic or pipeline imports. These markets are defined as "flexible" markets where alternative gas supplies give buyers a choice of where to buy their gas and means that the price of LNG will be determined by the price of the alternative gas supply. For the markets of Asia (Japan, Korea and Taiwan), they have no alternative gas supply and very limited domestic gas, with over 90% natural gas supply coming from LNG (Japan and Korea) and

	over 80% for Taiwan. These "firm" markets must have LNG to meet their energy needs and will effectively pay whatever price is needed to secure LNG cargoes. South America and Southern Europe, specifically Spain, (and some parts of USA where pipeline capacity is limited) can also be defined as a "firm" market
Mtpa	Million tonnes (LNG) per annum
NBP	National Balancing point (UK virtual gas trading hub)
NOC	National Energy (Oil) Company
Oil parity	Means that the price of a Btu of LNG increases/decreases the same as a Btu of crude oil. Since the average barrel of crude oil has an energy content of around 5.8 million Btu, this means that at full oil parity the LNG sales formula would be P(LNG) = (1/5.8) x P (Crude Oil); this formula calculates out at P(LNG) = 0.172 x P (Crude Oil). A constant, normally covering the cost of freight, is usually added to this formula. Sales of LNG into Asia in 1990-2002 had a multiplier to crude oil of 0.1485 (i.e. the price per Btu of LNG increased at ~ 86% of the oil price) with a constant of 0.6 – 0.9/ million Btu for ex-ship sales and zero for FOB sales. From 2003 onwards sellers, driven by the Qataris, have sought to increase the 0.1485 factor towards oil parity and Qatar has made sales to China and Korea on this basis
Peak shaving LNG plants	Small scale LNG plants that are used in domestic markets to store gas as a means of managing daily and seasonal gas demand fluctuations
Reserves	The amount of gas underground that can be commercially recovered - reserves are normally quantified in trillion of cubic feet (Tcf) or billions of cubic metres (BCM). The amount of gas in place underground is normally defined as a percentage of certainty that the gas can be commercially recovered.
TTF	Title Transfer Facility (the Netherlands virtual gas trading hub)
Third Party Access	Regulated third party access is where companies must give access to facilities on common terms e.g. if for any reason total volume requested exceeds available capacity then all usage parties must have their volumes reduced pro rata.
Unconventional gas	is gas produced from coalbed methane (coal seam gas), shales and seams rather than from gas reservoirs or associated gas from oil reservoirs

The LNG value chain is made up of four elements:

Upstream	The exploration (searching) for gas and, when found, the production of gas
Liquefaction	The process by which gas is cooled to minus 160 degrees centigrade at which point it turns into a liquid and contracts 600 parts to 1
Shipping	The movement of LNG is specialised tankers (not under pressure)
Regasification	The process whereby the LNG is converted back to gas through the addition of heat

[Downstream usually includes the regasification and market part of the value chain]

LNG Energy and Value Grid

Million Tonnes Per Annum (mtpa)	Billion Cubic Metres per annum (BCMA)	Number of "Standard" 145,000m3 cargoes	Trillion Btu (TrBtu)	Value in $ billion at different gas prices ($/MMBtu)			
				$4.00	$6.00	$8.00	$10.00
0.50	0.68	8.06	25	0.10	0.15	0.20	0.25
1.00	1.37	16.13	50	0.20	0.30	0.40	0.50
1.50	2.05	24.19	75	0.30	0.45	0.60	0.75
2.00	2.74	32.26	100	0.40	0.60	0.80	1.00
2.50	3.42	40.32	125	0.50	0.75	1.00	1.25
3.00	4.11	48.39	150	0.60	0.90	1.20	1.50

NOTE: All figures approximate and gas qualities vary

1 mtpa LNG = 1.37 BCMA Natural Gas
1 "Standard" cargo LNG = 62,000 MT LNG
1 "Standard" cargo LNG = 3.1 trillion Btu

Attachment 2 Colombia Gas and Power Data

A. Consumption of Gas by Sector

GBtu/day	Q1/08	Q2/08	Q3/08	Q4/08	Q1/09	Q2/09	Q3/09	Q4/09	Q1/10	Q2/10	Q3/10	Q4/10
Termoeléctrico	133.1	158.3	119.0	104.8	125.1	155.2	244.1	456.9	460.4	295.2	145.9	190.6
Industrial	267.6	268.7	272.1	266.0	238.1	243.3	244.8	227.1	218.6	243.3	254.4	254.8
Refinería	107.2	95.9	93.6	78.8	86.8	104.5	90.0	78.4	79.0	91.4	111.1	113.9
P/químico	14.8	10.9	11.9	10.4	8.8	12.4	11.5	11.9	12.1	12.0	12.0	12.1
Doméstico	146.9	151.2	149.6	151.0	148.9	148.7	148.6	147.3	149.3	146.2	149.8	160.7
GNCV	82.8	82.0	82.9	86.7	81.8	80.3	80.8	77.6	78.4	73.5	73.2	75.8
TOTAL Source: CREG	752.5	767.1	729.2	697.7	689.6	744.4	819.7	999.1	997.9	861.6	746.3	807.9

A. Consumption of Gas by Sector

	GENERACION HIDRAULICA SIN	GENERACION DE MENORES Y COGENERADORES	GENERACION TERMICA CARBON	GENERACION TERMICA FUEL OIL Y ACPM	GENERACION TERMICA GAS
Q1/09	121,574,537	7,943,114	6,895,012	484,212	14,629,311
Q2/09	115,626,356	7,932,485	8,932,891	435,941	18,628,128
Q3/09	108,516,568	6,868,680	12,016,177	1,073,747	28,830,489
Q4/09	78,984,281	7,559,378	12,567,078	4,713,961	51,619,911
Q1/10	75,387,259	5,902,783	14,480,221	5,685,666	53,357,910
Q2/10	98,950,162	9,491,814	10,255,013	3,051,071	34,655,976
Q3/10	123,604,605	9,321,775	6,513,119	484,215	16,088,729
Total	722,643,769	55,020,030	71,659,512	15,928,813	217,810,454

Attachment 3

Scope of Work dated 1st March April 2011 agreed between CREG and David Ledesma - South-Court Ltd

Task 1. To present technological alternatives of schemes to have LNG to supply thermal plants. It should identify the advantages and disadvantages of each of the proposed technologies.

- For a facility that must be commissioned before December 2014, to examine the following:
    - Development of different LNG supply options
    - The essential technical requirements of the different options? (e.g. size of jetty, what are the general specifications? Will tanks be needed? What is the land requirement?)
    - Give some dimensions of each option e.g what is the type of cost of each option? Full technical scope of work will not be prepared, only a high level view.
- What are the pros and cons of each alternative
- What is the recommendation?

Task 2. To design alternatives of business schemes for the development of facilities that were studied in task 1. These should be constructed by private investors without any type of government guarantees. Each proposed design should be specific about the role and task to be developed by each participant in the proposed structure. It should make an identification of advantages and disadvantages of each of the proposed alternatives.

- What are the different business structures that could be used?
- Structuring the companies to provide the following services (these may be the same or different companies)
    - Provision of the LNG importation and regasification infrastructure
    - Supply of the LNG
- To set out the commercial flows and structures of each option.
- To include the possibility of Colombian companies being involved as well as international companies –but this is not obligatory.

Task 3. To arrange meetings about schemes identified in task 2 to potential developers. It should identify and encourage potential applicants to attend to business meeting with generators.

- To arrange meetings with potential international companies who would like to develop an import facility.
    - A maximum of 4-5 company meetings will be arranged
    - There may be other companies who could be interested, but approached to these will have to be outside the scope of this assignment
- These meetings should ideally take place in Bogota but could be outside. It is the intention that representatives of CREG will attend these meetings.

Task 4. To evaluate the interest of potential developers. Once task 3 is completed to make contact with developers who attended the meetings to try to establish their real interest in continuing in the continuing in the process and identify possible adjustments required in the considered business schemes. In any case, within the work methodology, the consultant can add all the aspects that he considers as necessary and important for the achievement of the proposed goal.

- To consider the structure of attracting interest - tender or direct negotiations. If a tender, detailed invitation to bid will not be a part of this proposal. The issue is that a tender will open up more companies who can be involved and potentially lower the cost through competition. Also, companies may have new ideas as to how Colombia can cover their requirement. This process does take longer and cost more upfront (drafting of bid documents , review and assessment of the bids and award documentation).
- To set out a future work programme for CREG to follow such that it is able to move forward on the project

Attachment 4

What is LNG

The following section re-visits some on the basic parameters of the gas industry as they apply to the LNG business. It examines the basic physics of the LNG industry and attempts to clarify often confused terminologies. Given the Global nature of today's LNG industry it could well be the case that gas molecules produced in say, Asia or the Middle East, find their way into gas systems in Europe, the US or South America. This Global transport of molecules is the norm within the oil business which has maintained a Global footprint since its inception. Gas, however, is even today essentially a regional fuel where the gas is ordinarily produced, transported, sold and used within the same country or region. In other words, gas is not traditionally globally traded, it has not in the past "travelled" in the same way as oil. Additionally not all "gas" is the same and quality differences can have significant technical or commercial implications for LNG developers.

Gas and oil, when produced from hydrocarbon reservoirs, are a mixture of many different hydrocarbons, impurities and inert substances. Methane, ethane, propane, butane, pentane and higher, "Crude Oils", sulphur, helium, carbon dioxide, nitrogen, mercury, water and many others. Some of these components exist as liquids at room temperature and pressure (e.g. the oil related compounds), others exist as gasses[14].

Gas produced from reservoirs where the gas components form the majority of the flow are termed "dry gas" or "non-associated gas". Whereas gas produced from reservoirs where the oil components form the majority of the flow are termed as "associated gas". Whether associated or non-associated, the physical stream of gas from the production well will contain a similar mix of gas related compounds as noted above. Natural Gas, as the term applies to the gas industry, is this gas mixture resulting after processing of the raw (associated or non-associated) gas stream. The processing removes most of the higher hydrocarbons, inert compounds, impurities, water etc). Natural Gas is, therefore, a mix of hydrocarbons consisting mostly of methane (generally 95% or higher) with smaller percentages (generally 5% or less in total) of ethane, propane, butane, pentane, CO_2, nitrogen with very small traces of other compounds. As per industry norms - throughout the remainder of this report the term "gas" means Natural Gas i.e. consisting mostly of methane.

LNG or Liquid Natural Gas is gas that has been chilled to minus 161 degrees Centigrade or lower. At this extremely low temperature the gas converts into a liquid. Importantly for the LNG industry the cold liquid does not require the application of pressure to stay in liquid form. In other words, the liquid gas will stay in its cold liquid state even though only contained at atmospheric pressure. Containment systems in the LNG industry (e.g. liquid lines, LNG tanks, LNG ship storage systems etc) are therefore not generally pressurised – the whole chain works at or very close to atmospheric pressure. It follows that the key to containment systems within the LNG industry is to keep the liquid cool because as long as it stays cool then it will stay in its liquid form.

[14] A gas which exists as a gas at room temperature and pressure is always referred to as gas even though it could exist as a liquid under different phase conditions - for example as LNG or under huge pressure within a production reservoir.

The most import side effect of chilling to liquid form is that the gas condenses (liquefies) to occupy approximately one six hundredth of the volume[15] of the same gas at atmospheric temperature and pressure. This “expansion factor” allows the LNG industry to more easily store and transport the gas (as a liquid) without the need for heavy and expensive pressurised systems. In effect therefore the LNG industry, via chilling the gas to a liquid, solves an otherwise insurmountable transport and storage problem.

Other gas and related terms which often cause confusion in the LNG business are:-

LPG – Liquid Petroleum Gas. This is predominantly propane and/or butane which, given their higher molecular weights, can exist as liquids without the need to chill to cryogenic temperatures. These components can exist as liquids at room temperature via the application of relatively minimal increased pressures (generally a few bar or atmospheres). LPG is easily transported in bottled (in pressurised liquid form) and is produced from the same raw gas stream as that linked with Natural Gas or can be produced in refineries (oil product cracking). It is often used in domestic cooking or as a chemical feed stock.

CNG – Compressed Natural Gas. This is natural gas which is pressurized and stored at high pressure (from 7 to 100 bar depending on the application). This form of natural gas is most widespread within the road transportation sector, where the pressurised gas container is housed within the road vehicle and the gas used to power the vehicle’s engine in place of traditional petroleum/gasoline or diesel.

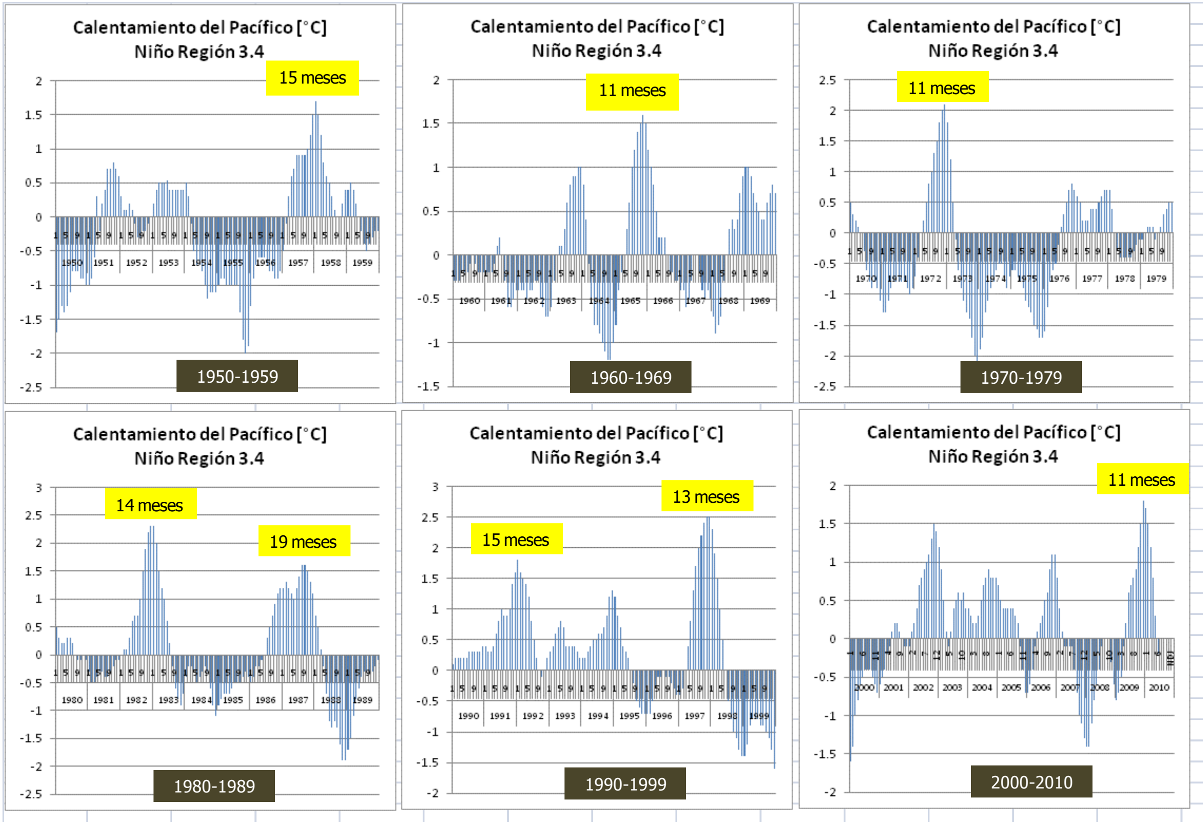
NGLs – Natural Gas Liquids. The generic name for LPG as above or LPG mixed with pentanes or higher gas related compounds (condensates see below). They are generallty not used in their natural state and are instead collected at gas processing facilities (or pipelines in the case of pentanes and higher) for sale to refiners. Importantly for the LNG industry pentane and higher compounds must be essentially removed prior to the liquefaction process to avoid the formation of waxes or solids which would otherwise block liquefaction equipment.

Condensates. Generally pentane or higher compounds – can be collected from raw gas pipelines or are removed in the first stages of gas processing. Generally sold to condensate refiners.

[15] 1/600 is the figure generally quoted by industry. However, the exact figure is normally between 1/580th to 1/600th depending on the exact gas composition.

Attachment 5

Periods of El Niño by decade (1950-2010)



Source: CREG