

Small and Medium size LNG for Power Production

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ABSTRACT

Over the past couple of decades, natural gas (NG) has become a fuel of choice for power generation. Production and transportation technology have developed considerably and NG is gaining popularity in other sectors, especially transport –both in marine and onshore. Even private vehicles are using an increasing amount of natural gas in its compressed form.

A crucial factor in enabling the spread of natural gas into new sectors is the development of NG distribution networks. Today, the most common method of distributing NG is via pipeline. However, the construction of pipelines requires significant resources in terms of investment and time, as well as overcoming bureaucracy. Also, for these pipelines to be profitable gas volumes must be large.

Another way of increasing the availability of NG is through the use of liquefied natural gas (LNG). Global LNG trade is expected to grow by 30% in the coming few years. Both production and receiving capacity must grow simultaneously due to the nature of LNG. In absolute terms production growth is expected to be from 270 MT per annum (2011) to around 350 MTPA by 2016. Re-gasification capacity today is around 660 MTPA.

A substantial part of this growth will come from the development of small and medium size LNG receiving and re-gas terminals. This demand for LNG terminals is particularly relevant in places where the gas infrastructure is under-developed but the demand for gas-fired power generation and natural gas for other industrial uses is large.

So far, the magnitude and investment costs involved in LNG projects have typically kept receiving terminals relatively large in terms of size/capacities and thus unsuitable for a ‘single gas consumer’ philosophy. Lately, however, there has also been small and medium scale LNG activity, with regional storage hubs from where a direct gas supply to consumers, small scale marine distribution tankers, or highway LNG trucks operate to and deliver LNG directly to the end user.

Recently there has been the question of whether a dedicated “Single Purpose” LNG receiving terminal would be feasible and make sense in a local energy mix. Such a terminal would be used for receiving and storing LNG for a certain process and possibly distribute it to other users in the local area. The capacity of such a storage facility would typically range from a couple of hundred of m³ to around 20,000 m³.

A Single Purpose Terminal (SPT) was recently studied in connection with a power plant concept based on simple cycle high efficiency reciprocating gas engines. The electrical power output ranges studied were 50, 100 and 300 MW.

The results suggest that in certain conditions a dedicated LNG receiving terminal (SPT) could be feasible as a total investment together with the power plant. The fuel gas price increase as a result of the terminal is, however, highly dependent on the total gas consumption and thus additional off-takers in the system would be desirable. In the following sections of this paper the details of the study are explained in more detail with related figures and illustrations.

1. INTRODUCTION

Most experts predict that natural gas demand will see strong growth in the future, increasing at a compound annual growth rate somewhere in the region of 7-8%. According to the International Energy Agency, we could be entering “a golden age for gas”. In its World Energy Outlook 2012, the agency projected that gas demand will rise from 3.3 trillion cubic metres (tcm) in 2010 to 5.0 tcm in 2035, an increase of 50%. Its share of the global energy mix rises from 22% in 2010 to 24% in 2035, almost catching up with coal.

Meanwhile, ExxonMobil’s Energy Outlook 2040 published in January 2013, forecasts that natural gas will emerge as the number one fuel for power generation within the next 30 years, accounting for 30% of global electricity generation. The attraction of gas as an energy source – whether for heating, transport or power generation – is clear. Its price relative-to-energy content is favourable when compared with other fossil fuels, and it significantly reduces SO_x and CO₂ emissions when replacing coal and oil in power generation.

With global LNG (liquefied natural gas) demand expected to show strong growth, LNG production is forecasted to jump from 270 million t/year in 2011 to 350 million t/year in 2016, according to the International Gas Union’s (IGU) World LNG Report 2011. This growth in production will have to be accompanied by a similar expansion in LNG receiving terminal capacity, since gas production is often not in the same location as consumption.

1.2. LNG Logistics Chain

The LNG logistics chain, from gas well to consumer, is a complicated and investment intensive business. The logistics chain can be split into three sizes: large scale LNG logistics chain (so-called conventional process); medium size LNG distribution; and small scale LNG distribution.

Large scale LNG operations

A large scale LNG operation is based on large multi-billion dollar industrial operations where gas from the production area is fed to a liquefaction site to produce LNG. These large sites typically include production trains with single capacities between 1 to 4 MTPA. They can include multiple trains. For example, in Qatar the main LNG production site has a total production capacity close to 50 MTPA. Large liquefaction sites are always located in coastal areas since the only practical method of large scale transportation is via LNG sea-going vessels.

Conventional receiving terminals (LNG hubs) in the large scale LNG chain are also located by the coast so LNG tankers can arrive and unload the cargo. Main hubs include LNG storage facilities typically in the range of 100,000 m3 or larger and can have multiple tanks in parallel depending on the capacity needed. The LNG is re-gasified at the hub and the main distribution channel for the consumers is normally a national high pressure NG pipeline.

In large scale operations LNG tanker capacities range from less than 100,000 m3 in older vessels to as much as 260,000 m3 in the largest Q-max vessels. Storage capacity at the hub is typically designed according to the allocated tanker capacity. The tanker should always be completely emptied at the hub, meaning that the full logistic chain: vessel size, hub storage capacity and gas off-take demand are strongly interconnected when determining the various parts of the chain.



Figure 1. Large scale LNG production and distribution chain: including gas production, liquefaction, shipping, local storage and distribution.

Medium scale LNG operations

When discussing the medium size LNG logistical chain, typical transportation vessel sizes vary from small, 1000 m3, to around 35,000 m3. Local medium size hubs or SPT storage capacity can vary from a few thousand m3 to close to 100,000m3 depending on the off-take volumes. Here again, vessel size plays an important role in determining storage capacity. LNG is normally fed from a large scale hub with LNG vessels typically operating regionally in a radius of around 1500 to 2000 nautical miles (NM).

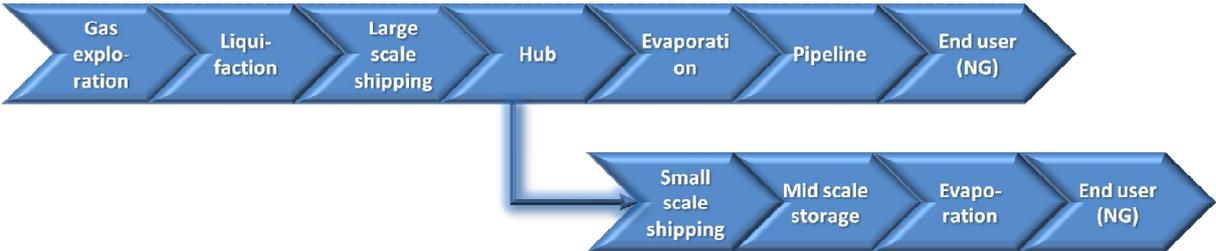


Figure 2. Medium scale LNG distribution chain starts from a Regional large scale Hub or in some cases directly from Liquefaction site. Local hub includes re-gasification and distribution of low pressure gas, if necessary high pressure gas and also according to demand possible local LNG distribution by road transportation.

Small scale LNG operations

A small scale LNG logistics chain normally refers to LNG distribution to local users. In practice this means highway truck transportation or small sea-going vessel distribution to end user local LNG tanks, which are typically tens of m³ in size. One special distribution channel is LNG as fuel for sea-going vessels. This is becoming more popular.

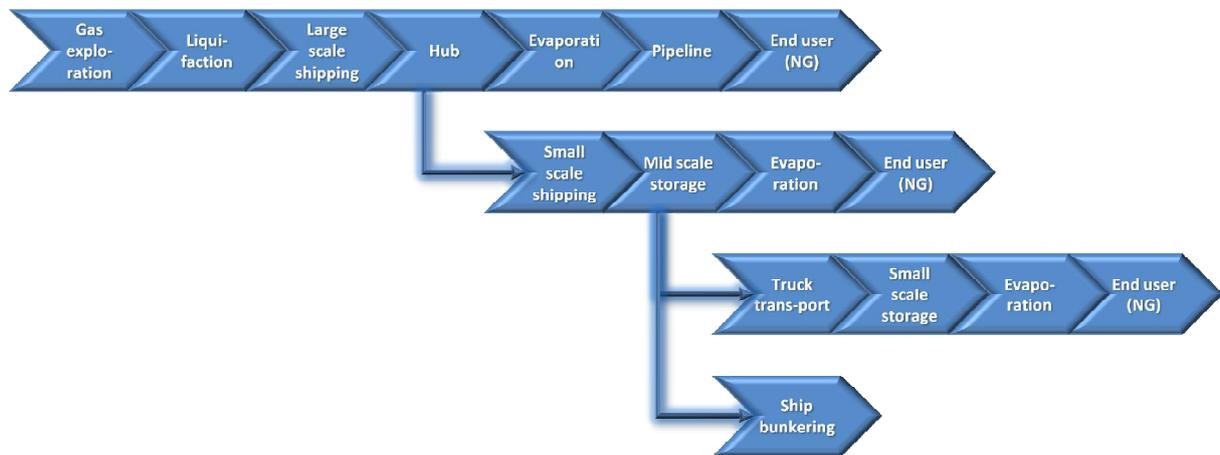


Figure 3. Small scale LNG distribution chain starts typically from Medium Size Hub. LNG is delivered at off-taker's local LNG tanks at the facilities where the gas is being used.

1.3. LNG Storage

One of the main questions to be addressed during the very early phase of a LNG terminal project is the technology to be used for the LNG storage facility. The two main solutions are: Floating Storage Re-Gasification Unit (FSRU) or a stationary on-site built facility for long term usage.

The decision is based on the economics when considering the entire lifetime of the project. Some of the main factors to be considered are: project life time, geographic and maritime conditions, local licensing bureaucracy, land lease/purchase conditions, investment costs and possible FSRU rental fees.

A floating storage and regasification unit is a ship or barge that is purpose-built or later fitted with LNG tanks and the necessary heat exchangers (gasifiers) for converting the liquid into gas. The gas is transported to land by a gas pipeline, which has flexible connections between the FSPO and jetty. A FSRU may also be placed next to the gas consumer, e.g. a gas fired power plant. FSRU storage capacities are typically 80,000-160,000 m³.

When on-shore installation is the right solution, two main technical solutions are considered. These are either large atmospheric full containment tanks or pressurised double-wall steel tanks in multiple set-ups according to capacity needs. The decision on which solution to use is again an overall economic optimisation task where the required storage capacity and gas distribution pressure, together with the investment, play the major role.

Atmospheric pressure tanks

Traditional, large, land-based LNG tanks are designed for atmospheric pressure only. These tanks are built on site on flat-base concrete foundations. They are not designed to withstand

over-pressure, meaning that the inside pressure has to be maintained equal to the outside atmospheric pressure. The only way to ensure this is to have a system to handle the boil-off gas, by converting this gas back into liquid form via a reliquefaction system or removing the vaporised gas by other means.

Pressure tank technology is typically selected for LNG storage tanks larger than 10,000 m³, while smaller storage tanks are often built using several pressurised steel tanks. Atmospheric pressure tanks can be built in three different ways; single containment, double containment and full containment. Each type has advantages and disadvantages, and selection depends on location.

Pressurised small-scale tanks

LNG can be stored in cylindrical metal tanks designed to typically resist pressures of up to 10 bar. The benefit of having pressurized tanks is that the boil-off gas, which is inevitable no matter how good the thermal insulation is, can remain in the tank and act as a pressure source for gas feed. When the excess pressure is controlled by releasing gas through a control valve, the evaporation inside the container lowers the temperature and keeps the container in equilibrium.

As a result, the tank arrangement is extremely simple, having no compressors or rotating equipment of any kind. It simply consists of the tank, an emergency pressure relief valve, regasification heat exchangers, and an outgoing gas pressure stabilisation valve.

Pressurised small-scale LNG tanks come in different sizes, ranging from very small tanks for vehicle use, up to larger tanks of several hundred cubic metres, and even up to about 1000 m³ in capacity. Their size is limited by transport constraints and weight. For example, a tank of 1000 m³ is over 45 m long and 6 m in diameter. Typically, a number of tanks are placed side-by-side to get to the desired overall volume. Even larger pressurised LNG tanks of 10,000 m³ and more do, however, exist. The pressure resistance of the larger tanks tends to be smaller, about 4.5 bar (65 psi), as the weight and cost of the tank steel would otherwise become cost prohibitive. These larger pressurised tanks have so far only been used on ships and barges, due to transport limitations.

2. SINGLE PURPOSE LNG TERMINAL BASED POWER PLANT

2.2. General

In this study, the feasibility of a LNG fired power plant with various LNG terminal capacities and NG off-takes was evaluated. The technical solution and criteria for selection is presented in this chapter.

The study was conducted for three power plant sizes with the following approximate electrical outputs at 35°C ambient conditions: 50 MWe, 100 MWe and 300 MWe.

Each power plant size was analysed both as a standalone gas consumer and with additional off-takers with a similar gas demand as the power plant itself.



Figure 4. On-Shore 100 MW power plant layout with full plant infrastructure including switch yard and high voltage transformers, liquid fuel tanks for possible dual-fuel set-up and other service and storage facilities needed.

2.3. Power Plant

The technical solution and main parameters of the power plants considered were based on a simple cycle power plant configuration under tropical conditions. High efficiency, lean-burn reciprocating gas engines were selected as prime movers. The 50 MW and 100 MW plants were based on multiple engines each with an output of 9 MW per unit and the 300 MW plant was based on multiple 19 MW units. Sizes are as follows:

- 50 MWe, based on 6x9 MW ISO output
- 100 MWe, base on 12x 9 MW ISO output
- 300 MWe, based on 18x 19 MW ISO output

The ISO output is the engine output at ISO standard conditions (for reciprocating engines according to ISO 3046 ambient temperature: 25°C, and height above sea level max. 100 m). Actual output will depend on site ambient conditions. For example, it will be slightly less in more extreme conditions. To determine the actual power output of each plant the following ambient conditions were used:

- Maximum Ambient Temperature: 35°C
- Average Annual Ambient Temperature: 29°C
- Power Plant Site Altitude max.: 100 m.a.s.l.
- Average humidity: 70%
- Methane Number of fuel gas >80

After the correction calculations according to standard ISO 3046 the actual plant net outputs were as follows:

- 53 MWe, based on 6 x 20V34SG gas engine
- 106 MWe, base on 12 x 20V34SG gas engine
- 304 MWe, based on 18 x 20V50SG gas engine

Equally, plant fuel consumption was corrected from the standard ISO values. The following adaptations were considered: values given as real 0% tolerance with applied ambient related

correction factors, plant internal consumption has been removed from the net power and a lifetime average degradation of the efficiency between maintenance intervals has been included. This gives expected fuel consumptions as follows:

Power Plant Size day(MW)	Electrical Efficiency (Heat Rate)	Fuel Power (MW)	LNG volume per (m ³ /day of liquid gas)
53 MWe	43.1% (8271 kJ/kWhe),	123 MW	511 m ³ /day
106 MWe	43.2% (8250 kJ/kWhe)	245 MW	1022 3/day
304 MWe	44.5% (8013 kJ/kWhe)	683 MW	2840 3/day

When looking these values and the absolute consumption of LNG volume, the fuel consumption can be presented as shown in Figure 4 below. The storage tank optimisation is based on these curves and external factors as presented later.

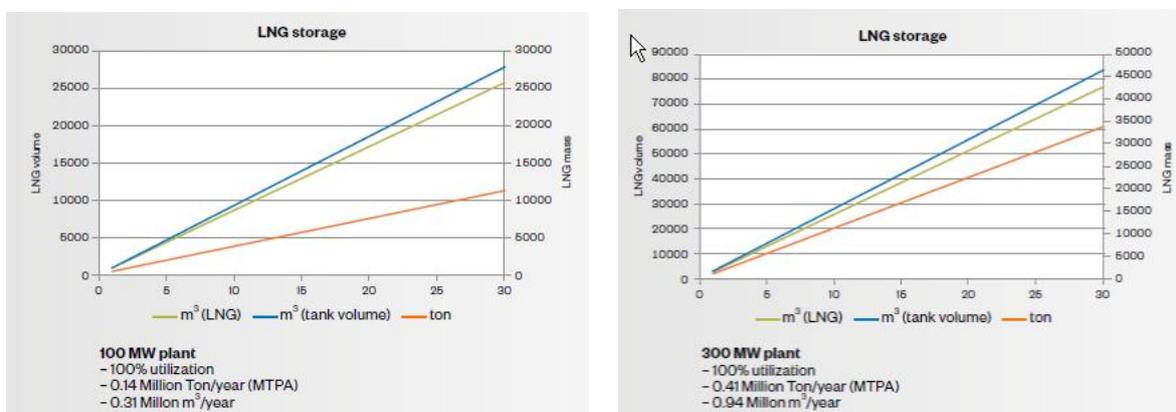


Figure 5. LNG consumption as function of days for 100 and 300 MW power plants.

2.4. Receiving Terminal

In the case-specific feasibility evaluation it became evident that, in terms of technology, the terminal is based on on-shore receiving, storage and regasification Terminal (RSRT) solution. The terminal would be located at the sea shore in a tropical climate zone.

The proposed receiving terminal is optimised according to expected gas consumption, available LNG distribution hub and tanker vessel. It would be established in connection with an existing harbour infrastructure so that no jetty investment is needed.

The storage tank technology chosen for comparison is an atmospheric concrete full containment tank. The capacities are chosen for each case separately (see below chosen tank sizes).

Two processes are considered for the LNG re-gas system:

1. Gas supplied at low pressure (8 bar) only as fuel for the power plant,
2. Gas supplied at high pressure (50 bar) to pipeline off-takers and at low pressure (8 bar) for the power plant.

Low pressure supply system

When the gas off-take is exclusively low pressure (8 bar), the LNG re-gasification and process equipment are relatively simple. The gasification can happen with hot liquid (steam or hot water) or ambient air as the heat source for the heat exchanger. The main components of the LNG terminal are: vessel off-loading arrangement, storage tank with immersed LNG pumps, boil-off gas compressors and heat exchangers for LNG gasification and heating. This process equipment is typically located in the same area as the storage tank. The evaporated gas is fed into the pipeline system for off-takers, in this case to a power plant. When low pressure gas is used, consumers are normally in close proximity to the terminal.

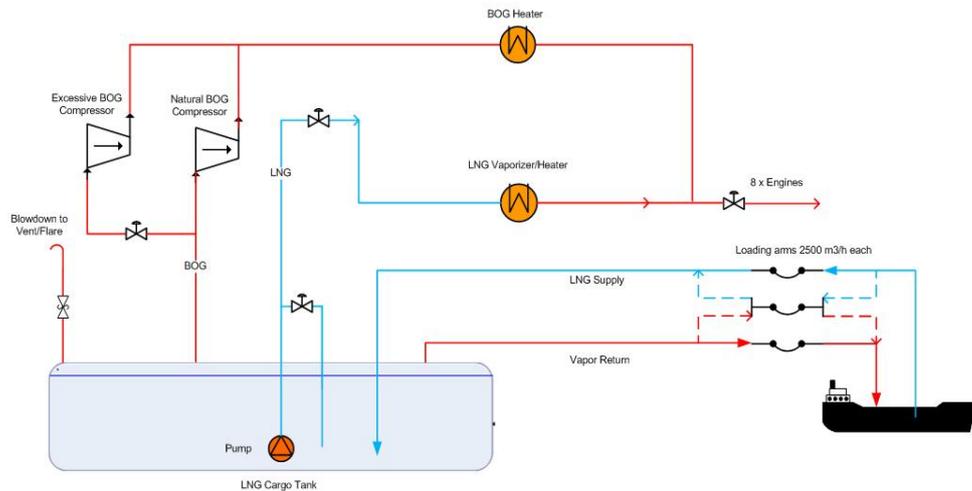


Figure 6. Schematic illustration of the process principle of Medium Size LNG receiving terminal with low pressure (8 bar) natural gas supply system.

High pressure supply system

To improve the economics and overall feasibility, it would be beneficial to have additional gas off-takers in the system. If this is the case then normally the additional gas is distributed through a high pressure pipeline (50 bar). This means that the terminal LNG process must include, in addition to the previously described low pressure system, a high pressure re-gasification system. The high pressure is achieved by using high pressure LNG pumps prior the gasification heat exchangers acting on the liquid side of the LNG flow.

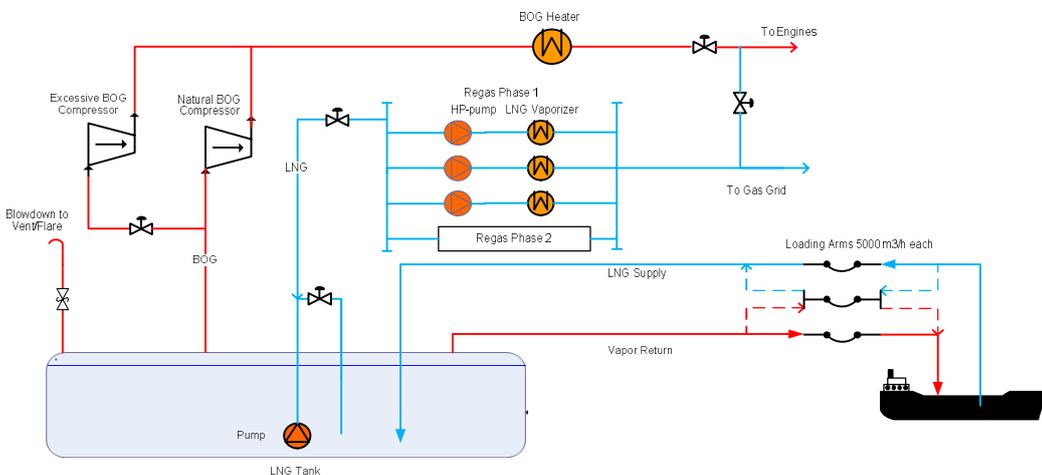


Figure 7. Schematic illustration of the process principle of Medium Size LNG receiving terminal with high pressure (50 bar) natural gas supply system to the pipeline off-takers and low pressure distribution system for next door power plant.

Storage Tank Size Determination

For the low and high pressure supply system the tank capacities were chosen to be as follows:

Power Plant Size Size (MW)	LNG Storage Tank Size	LNG Storage Tank Size
	Low Pressure	High Pressure
50 MWe	10,000 m ³	25,000 m ³
100 MWe	20,000 m ³	45,500 m ³
300 MWe	57,500 m ³	90,000 m ³

The parameters for determining the minimum tank size for each plant are: gas consumption, shipping information and minimum safety inventory for transportation operations and tank minimum reserves.

The shipping assumptions are: distance between delivery hub and local terminal (1500 NM); ship average speed (15 knots); and a hired dedicated non-stop vessel serving the terminal. In this case the optimum vessel sizes for various cases are:

Power Plant Size Size (MW)	LNG Tanker Size	LNG Tanker Size
	Low Pressure	High Pressure
50 MWe	6000 m ³	13,000 m ³
100 MWe	12,000 m ³	30,000 m ³
300 MWe	35,000 m ³	52,000 m ³

For additional security, a 7-day emergency inventory of LNG storage capacity was calculated. This allows for any unplanned interruption in LNG supply. Also, a 10% heel requirement was considered i.e. the level that the LNG in the tank should never fall below. This secures the cryo-temperature (-160°C) in the tank at all times.

The technical solution just presented is used for the feasibility study in the following chapter. The basic assumption is that the jetty, terminal facilities and power plant systems are located in the same area. This will be particularly effective when the entire project is being executed under a single EPC contract, allowing both LNG terminal and power plant to be constructed in parallel to shorten overall construction time.



Figure 8. On-Shore 100 MW power plant with dedicated “Single Purpose” LNG Receiving Storage and Re-Gasification Terminal (RSRT).

3. FEASIBILITY CONSIDERATIONS

3.2. General

The viability of a “Single Purpose” LNG Terminal together with a power plant has long been considered.

To look at this set-up in more detail, technical, economic and feasibility criteria have to be established. The technical solution matrix was discussed in the previous chapter. Power plant alternatives together with LNG terminal selection were presented. The economic parameters and feasibility criteria will be described in the following chapters together with the investment analysis and final conclusions.

The analysis was performed in two steps. Firstly, a simulation was performed to determine the effect of LNG transportation and terminal investment to the FOB (Free On Board) price of purchased LNG in order to reach a “Terminal Effect” for the cost of gas. This price analysis was performed for all three power plant sizes – as a standalone gas consumer and with additional gas off-takers increasing the gas volume in question.

After this first step, a traditional power plant feasibility analysis was undertaken using the higher gas prices as the input fuel cost for the plants. Certain investment criteria were used to calculate theoretical electricity sale prices. The final conclusions are based on the electricity price comparison of various cases together with other key factors that affect the results.

3.3. Terminal Effect on Gas price

Background

World LNG prices are controlled by a few regional pricing mechanisms. In the western hemisphere (North and South America) prices are based on the so-called Henry Hub system. This price is relatively low today (summer 2013) below \$4/MMBtu and is under pressure to stay so due to, for example, the large amounts of shale gas available in the US.

In Europe, Russia and North Africa the gas market is a mixture of some LNG and mostly pipeline NG. Here pipeline gas pricing is often linked to oil price and the LNG brought into the market follows the pipeline gas price. Gas price today is in the range of \$9/MMBtu.

The Asian market has traditionally been very LNG dependent, led by Japan. The fast growing economies together with the Fukushima nuclear accident has raised LNG demand to new heights keeping LNG prices in the range of \$15/MMBtu or more.

When considering a new “Single Purpose” LNG receiving terminal in South East Asia, the FOB price (before transportation) would be around \$15 depending on the volumes and location.

The cost increase from the FOB price to power plant input price (Terminal Effect) is derived from the following factors:

- shipping cost
- LNG tank and process related capex costs

- LNG high pressure re-gasification system capex cost
- other capex
- working capital for LNG in the vessel and tank
- annual LNG Terminal operational costs

LNG volume rate

Gas volumes constitute a key part of the gas cost analysis. The total annual volume of LNG is a factor of power plant size and load profile and other possible off-take gas volumes. In the analysis the power plants run for 7000 h per year at an average load of 80%. For each plant alternative, a parallel case was considered where there is additional gas off-take (re-gas) in a similar range as the power plant fuel consumption. In this scenario the total LNG consumption on an annual basis is as follows:

Power Plant Size (MWe)	LNG Peak Demand (full load)		LNG Average Demand (average load)	
	(m3/year) No off-take	(m3/year) With off-take	(m3/year) No off-take	(m3/year) With off-take
53	186,500	442,600	119,200	247,300
106	372,900	869,200	238,400	478,500
304	1,035,900	1,676,600	662,200	950,600

Peak demand is an estimation of consumption if the power plant and off-takers are operating at 100% capacity throughout the year. The facility storage and re-gasification dimensioning is based on peak demand.

LNG purchasing is based on the estimated real annual consumption, which in turn is calculated as average demand.

Estimated LNG FOB prices as MMBtu in this hypothetical case are given in the table below. The price per MMBtu is a function of annual volume as it falls below \$15.

Power Plant Size (MWe)	Estimated FOB Cost	Estimated FOB Cost
	No off-take	With off-take
53	\$17.82	\$17.11
106	\$16.39	\$15.68
304	\$14.97	\$14.25

LNG Shipping Cost

LNG shipping between the FOB sales hub and new terminal can be arranged in three ways: operating your own LNG carrier; contracting a carrier from the market place; or arranging transport through an LNG provider.

For the first two options, freight volumes should be significant in order to establish in-house organisations to manage this. The third option is the norm when volumes are small or moderate. In this case the entire supply chain and associated risks can be sub-contracted as one package to LNG providers. In the study it was considered as an all-in shipping cost to be provided by the LNG provider. Cost depends on the estimated average annual LNG volume

and storage tank capacity which, together with the consumption rate, distance and available vessel capacities, dictates the vessel frequency needed.

With the LNG consumption presented above and tank and vessel sizes as presented in chapter 2.3 the all-in LNG transportation cost per MMBtu is estimated to be:

Power Plant Size (MWe)	Estimated All-In Cost \$/MMBtu (HHV)
53	2.14
106	1.85
304	1.43

Capex related Costs

An LNG terminal represents a huge investment. The capital expenditure (Capex) is typically divided into: receiving and storage; re-gasification; and other investments, such as land, other on-shore infrastructure and possible marine and off-shore infrastructure.

Also the initial LNG average inventory and related working capital are considered as part of the investment. In this case the average capital tied into LNG inventory on an annual basis varies between \$3 million and \$22 million, depending on the size and consumption of the terminal.

The project lifetime is estimated to be 25 years, which is used for calculating depreciation. Weighted average cost of capital is assumed to be 10%. When looking at very rough investment estimates, the effects on gas price are as follows:

Power Plant Size (MWe)	Rough Investment (Million \$)	Cost Increase \$/MMBtu as (HHV)	
		No off-take (\$)	With off-take (\$)
53	75	4.09	2.04
106	102	2.28	1.47
304	185	1.60	1.34

LNG terminal operating costs

Operational expenditure (Opex) is made up of manpower costs and maintenance costs. The manpower needed in terminals of various sizes is more or less the same for the basic operation. In certain cases there could even be some synergies between the terminal operations and power plant operations, especially in control and monitoring functions. This is particularly true when the terminal and power plant are located at the same site.

Annual maintenance costs depend on the size and capacity of the terminal. A normal assumption for maintenance cost for this type of facility is around 1 to 2 per cent of the investment cost per year. In this case it would mean a few millions dollars per year, depending on the terminal size. Operational costs are estimated to influence the final gas price according to the table below.

Power Plant Size (MWe)	Estimated Opex	Estimated Opex
	No gas off-take (\$)	With gas off-take (\$)

53	1.57	0.76
106	1.05	0.52
304	0.47	0.33

Effect of terminal on costs of gas and final distribution

From the above considerations it can be seen that the new gas price after the terminal is heavily dependent on annual volumes. Additional off-takers are therefore important for the economics of the project. When adding up the effects of transportation, investment, working capital and operational costs, the effect of the terminal on gas cost is given in the table below.

Power Plant Size (MWe)	Terminal effect on Gas Cost	Terminal effect on Gas Cost
	No gas off-take (\$/MMBtu)	With gas off-take (\$/MMBtu)
53	5.66	2.80
106	3.33	2.00
304	2.07	1.67

The final distribution cost from the terminal is the FOB price added to the Terminal Effect as shown below.

Power Plant Size (MW)	Cost of Gas for Distribution	Cost of Gas for Distribution
	No gas off-take (\$/MMBtu)	With gas off-take (\$/MMBtu)
53	25.62	22.04
106	21.57	19.53
304	18.47	17.35

The following chapter briefly presents a simple power plant feasibility analysis using these new gas distribution costs as fuel cost. These costs are still based on Higher Heating Value (HHV) of the gas. As power plants naturally operate according to the Lower Heating Value of the fuel, this has to be taken into account in the feasibility calculation.

3.4. Power Plant Feasibility Analyse

General

The feasibility analysis involved simulating possible electricity sales prices with the above presented fuel cost and certain investment and operating costs. The plant performance is according to the tables presented in chapter 2.2. where the key parameters affecting the results are the Net Power Output (NPO) and Net Fuel Consumption (NFC).

The Net Power Output is the actual power available for sale after the high voltage transformer at the point of connection to the purchaser's electrical grid. This output alters with ambient conditions and represents what is available during the most severe temperatures at the site. Similarly the Net Fuel Consumption corresponds to the same situation as the NPO, i.e. the actual fuel consumption under worst case ambient conditions.

The plant operating profile normally depends on the power purchase agreement and actual demand from the grid. Normally power plants do not operate at 100% capacity all-year-round. In this evaluation it was assumed that in each case, the plants run for 7000 hours per year at an average load of 80%. This corresponds to a capacity factor of 63.9%, meaning that the plant's 'full power hours' on the duration curve of the annual total hours is 5600 hours.

Financing Scheme

Often a power plant investment package is made up of equity from investors and bank loans from outside institutes. In the feasibility modelling, the financing principle is a simple full equity investment by investors. This method is adequate for comparison purposes since the comparison parameter is an electricity sales tariff structure split according to fuel cost, variable and fixed operational costs, and dividends.

All the finance-related costs are covered by Return On Equity (ROE), which in this case was set at 15% – a level generally regarded as sufficient by investors. The return on investment is paid through annual dividends that cover the payback and interest for invested equity. A simple pay-back can be calculated by dividing the total investment by the annual dividend.

Plant Investment

Total power plant investment comprises the EPC contract value, mobilisation costs and other up-front costs, such as project development, land purchase and connection costs. The total investment scheme is estimated below:

Power Plant Size (MWe)	Total Investment Cost (million \$)	EPC Investment (\$/kWe)
53	60	887
106	105	849
304	280	847

Operational Costs

The biggest operating cost is fuel. Fuel cost is based on the costs presented in chapter 3.2. and the annual running hours according to the capacity factor. Other operating costs are lube oil consumption along with variable and fixed operation and maintenance (O&M) costs.

As the prime movers are reciprocating lean-burn gas engines, lube oil cost should be taken into consideration in the model. The units in question typically consume around 0.3 g/kWh of lube oil during operation. Lube oil typically costs around \$1/litre.

Variable O&M cost for this type of plant is around \$7/MWh; this includes consumable spare parts and manpower for service activities and operation. Fixed O&M cost is in the range of \$5-10 per installed kW per year depending on the plant size.

Feasibility Study Results

Results from the modelling provided an electricity selling tariff and an investment dividend ratio per year.

The electricity tariff is given as \$/MWh. Results from the study show an investment criteria of 15% ROE would be reached. The results compared:

- Electricity generation tariff using both FOB price and Terminal Effect gas prices
- Electricity tariff with three power plant outputs
- Electricity tariff with and without additional gas off-take
- Electricity tariffs are shown in the chart below with the tariff structure:

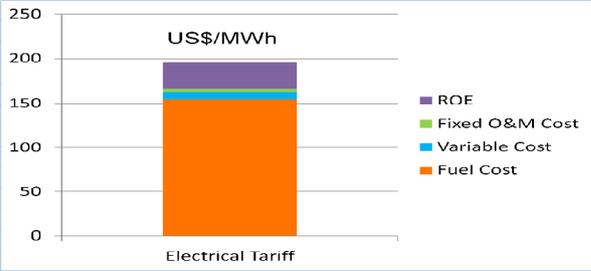


Figure 8.Principle of tariff structure with four constituents: fuel cost, variable cost, fixed cost and ROE.

The charts show the weight of each of the four elements of the final electricity sales tariff. The purple area represents the ROE which is needed to reach the 15% return. The main part in the tariff structure is the fuel cost which is the actual variable in the tariff comparison presented below.

The total tariff structure has been formulated for each plant size with the following considerations:

FOB gas prices are used to compare the terminal solution with a set-up where the plant would be fed with gas directly from the source, meaning that the gas price in that case would be the FOB price

It is assumed that in both cases gas price would vary depending on the gas volumes in question. This has been indicated by calculating the values in ‘no re-gas and ‘with re-gas’ cases.

Tariff structure shows the four main constituents making up the total price.

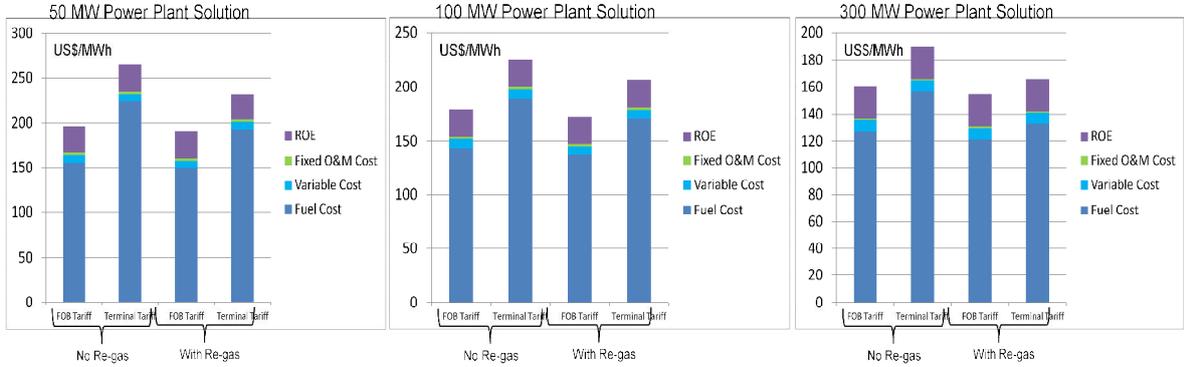


Figure 9.Power Tariff Structures with FOB and Terminal Effect gas prices. The effect of gas volume can be seen on the tariffs, Re-Gas meaning additional gas consumers in high pressure level.

When focusing on the Terminal Effect on gas price and final power tariff, it can be seen that fuel cost dominates the tariff and is of utmost importance when analysing the results. O&M and ROE-related components are relatively constant as well as the sensitivity related to investment itself.

The results for the tariff structure for Terminal Effect without and with re-gas activity are shown in Figure 10 below:

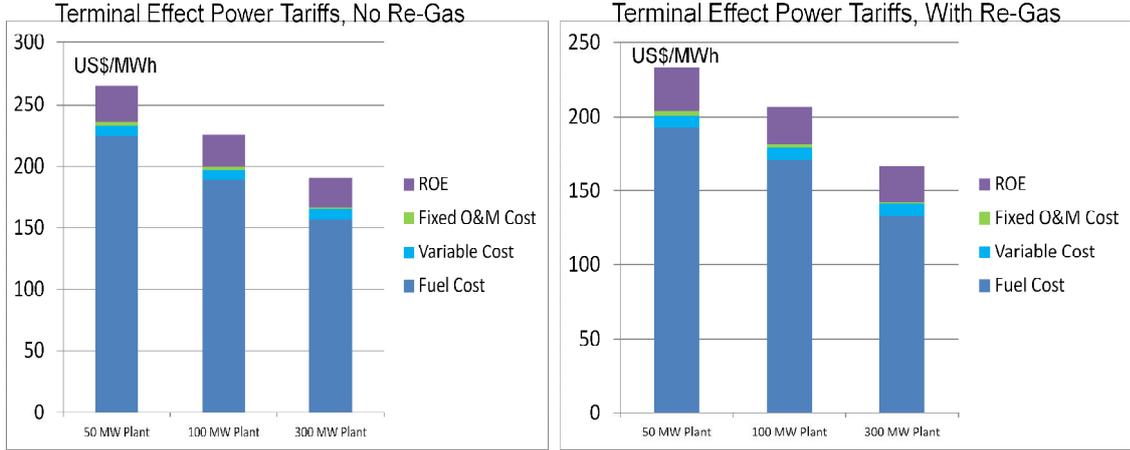


Figure 10. Terminal Effect on Power Tariff Structures as function of gas volume. Re-Gas meaning additional gas consumers in high pressure level.

4. CONCLUSIONS

The global expansion of the LNG gas market is being driven by steady growth in power production, industrial usage and the increasing use of LNG as a fuel for transport. This growth scenario of more than 10% per annum, however, not only depends on expanding LNG production capacity but also increasingly on the local availability of LNG in liquid or gaseous form. The expected growth of receiving and re-gasification capacity will be increasingly seen in the small and medium size terminals. This will also act as a trigger for wider LNG usage as marine fuel.

Power plants in the 50 to 300 MW range are often fuelled by NG or liquid fuels such as heavy fuel oil (HFO). In a new project development the availability and logistics of fuel become one of the most important decisions.

With environmental impact and legal framework playing a big part in fuel choice, today NG is often the preferred fuel. If NG is not readily available, a solution can be a dedicated Single Purpose LNG Receiving Terminal to act as local NG supplier.

If affordable electricity can be generated with LNG FOB based pricing, then there is often a combination of parameters where a Single Purpose medium size LNG import terminal can also be a feasible solution.

In the above chapters it was concluded that the LNG cost increases from FOB purchase price to distribution price after the Terminal Effect. The degree of price increase is heavily

dependent on the LNG volumes in question. The difference in Terminal Effect when comparing a 50 MW power plant as a single user to 300 MW plant with additional re-gas capacity is nearly three times more for the smallest consumption.

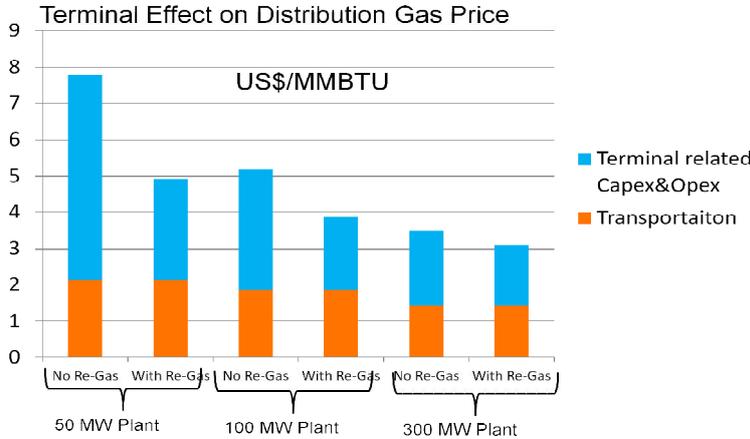


Figure 11. Terminal Effect as US\$/MMBTU for various power plant sizes with and without re-gas activity.

When assessing the total distribution gas price, which is made up of FOB price and Terminal Effect, the results are no longer so severe. The highest gas price of \$25.6/MMBTU is around 32% higher than the lowest gas price in the 300 MW power plant case.

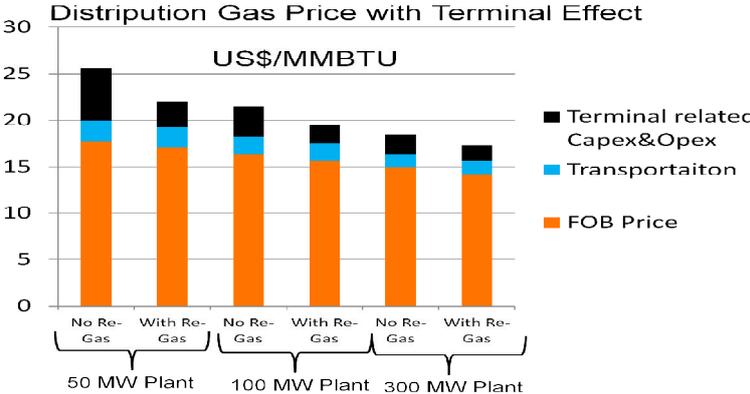


Figure 12. Distribution gas price with FOB price and Terminal Effect as US\$/MMBTU for various power plant sizes with and without re-gas activity.

Terminal Effect power tariffs vary between \$264/MWh and \$166/MWh according to the various distributions gas prices. These values would deliver a 15% ROE, which corresponds to a simple pay-back time of about 6.5 years.

In conclusion it can be said that with the chosen set of parameters, a Single Purpose LNG Receiving Terminal can be a feasible alternative for a power plant fuel feeding system. The factors needed to reach an acceptable tariff are the initial FOB gas price and the LNG volumes in question. Additionally the location of the LNG Terminal and possible existing structures that can be utilised – e.g. harbour facilities, existing industrial area for the development and good land access – help reduce the initial infrastructure investment.

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