LNG as a Vessel and General Transportation Fuel Developing the Required Supply Infrastructure

Author Name(s): G. W. Van Tassel (M)

Society of Naval Architects and Marine Engineers
2010 Annual Meeting
Bellevue, Washington

LNG as a Vessel and General Transportation Fuel Developing the Required Supply Infrastructure

Author Name(s): G. W. Van Tassel (M)

LNG holds great promise as a transportation fuel making significant reductions in emissions and green house gases. The road to increased use of LNG as a heavy transportation fuel in the U.S. is the development of a coherent LNG supply infrastructure. The existing LNG import terminal infrastructure can be leveraged to implement a safe and reliable fuel supply infrastructure. This paper will discuss the transshipment of LNG, by an AT/B LNG carrier, from existing U.S. LNG import terminals, in a hub and spoke arrangement.

KEY WORDS: LNG; LNG fuel; LNG carriers; Short Sea

INTRODUCTION

LNG holds great promise as a transportation fuel making significant reductions in SOx, NOx, CO_2 and particulate emissions. These reductions are in excess of even the most far reaching emissions regulations without the need for exhaust gas treatment methodologies. The use of LNG as a transportation fuel for city fleet vehicles, dedicated trucking routes and even rail locomotives has been demonstrated with solid success. The success of LNG as a liquid fuel also applies to vessels including harbor tugs, ferries, supply vessels, short-sea shipping RO/RO and container vessels, and deep-sea vessels for in-port power requirements. The technology is well established with a number of noteworthy vessels in service and under construction. Furthermore, the increased use of LNG as a transportation fuel, replacing traditional distillates, has the extended benefit of reducing dependency on crude oil and easing the burden on domestic refining capacity.

The road to increased use of LNG as a transportation fuel in the U.S. is the development of a coherent LNG supply infrastructure. Without an effective infrastructure for LNG as a fuel, it will never reach its true potential and will be condemned to local niche markets only. The Natural Gas Act of 2009 makes an attempt to address this need, but even if passed and signed into law, it will likely have limited effect, as the current national vision is limited. Traditionally, LNG is seen as a supplement to pipeline gas as either base-load importation or local distribution company's needle peak shaving. LNG in this respect has had a roller coaster ride. Once again, supply is outstripping demand, import terminals are underutilized and the LNG carrier sector is over tonnaged, with many vessels in lay-up status.

The use of LNG as a marine fuel in the U.S. is virtually non-existent. On the land based transportation fuel side, LNG, as fuel, is generally produced by liquefying pipeline gas, in small-scale liquefaction plants, in highly localized areas. The existing LNG import terminal infrastructure, however, can be effectively leveraged to implement a safe and reliable fuel supply infrastructure that will support significant conversion from the use of distillate fuels to LNG with significant, and near term, emissions reductions, reduced dependency on crude oil and demand on refining capacity. The added cost of re-gasification at the import terminal and the cost of local liquefaction on the downstream pipeline side are also avoided. This approach is being successfully applied in Norway with a variety of vessels from offshore supply, ferries, RO/RO, etc. in service and on order.

This paper will discuss the conceptual approach of transshipment of LNG from existing world class LNG import terminals, in a hub and spoke arrangement, to distribution points suitable for the expansion of the use of LNG as a transportation fuel for both land-based and marine. A key element to the implementation of this approach in the U.S. is an economic short-sea, Jones Act, LNG carrier. The design aspects of a coastal transshipment LNG carrier based on proven articulated tug / barge (AT/B) technology will be discussed for a series of vessels of varying capacity. The vessel(s) in question is currently in contract level design phase and will soon be submitted for regulatory review. The application of the subject vessel to specific U.S. coastal, short-sea, trade routes will be explored. The application of the concept and vessel described herein are, however, not limited to just the U.S.

NATURAL GAS AS A TRANSPORTATION FUEL

There are significant benefits to the increased use of natural gas as a transportation fuel. Internal combustion engines running on 100% natural gas produce far less pollutants, compared to current and future tier engines on low sulfur fuel, and a significant reduction in CO_2. Lean burn natural gas engines can be expected to reduce CO_2 emissions by 20%. This is principally due to the low carbon content of methane consisting of one carbon atom with four hydrogen atoms. This is the lowest carbon content of any fossil fuel. Furthermore, LNG has no sulfur to speak of, so SOx emissions are nonexistent with reductions of 98 to 100%. An approximate 80% reduction in NOx emissions can also be expected with lean burn engine technology, without exhaust gas post treatment such as Selective Catalytic Reduction (SCR) technology, urea injection, etc.

Finally, particulate emissions are similarly reduced to near zero except under the most difficult engine load changes[1]. These emission reductions are achievable today, without reliance (or impediment) on developing enabling technology, by switching from light distillate fuels to natural gas. It must be pointed out, however, that the reduction of CO_2 can be countered very quickly if the engine passes unburned methane (CH_4) through to the engine exhaust, as methane is a far more potent greenhouse gas than CO_2. Many earlier natural gas engine conversions, where the natural gas is simply introduced into the intake air, are particularly prone to passing un-combusted methane through to the exhaust. This is particularly important when evaluating emissions of early adoption natural gas engines and attempting to draw conclusions about emission reduction potential with modern engines.[2] Evaluating early adoption installations is historically useful, but must be tempered with the understanding that the technology has moved forward from that point. It would be a disservice to conclude that meaningful green house gas and pollutant reduction is not achievable by switching to natural gas based on old technology. The off the shelf technology available today is very much different.

At current pricing, natural gas fuel on a Gasoline Equivalent Gallon (GEG) or Diesel Equivalent Gallon (DEG) is a lower cost fuel option. This is, of course, very much regionalized and commodity driven. On a straight energy content basis natural gas has enjoyed a historic 40% price advantage over diesel. Every indication suggests this cost difference will stand. It is important to remember that this price advantage does not include the cost of making LNG available in port areas. Nonetheless, LNG can be expected to be competitive versus light distillates. Conventional liquid fuel cost will likely rise, however, particularly in light of the requirement to produce ultra low sulfur diesel fuel (ULSD, sulfur < 15 ppm) beginning in 2012. Recent shale gas finds suggest that the U.S. will have substantial natural gas reserves leading to an expectation that natural gas prices are likely to remain relatively stable with a much shallower slope to the cost curve looking forward. The relatively low natural gas pricing at Henry Hub[i] in comparison to pricing on a worldwide basis is a principal reason that the U.S. is not seen as a particularly attractive market on a worldwide scale.

The less tangible, although no less important, benefit to increasing use of natural gas as transportation fuel is a significant reduction in demand for imported oil and a reduced demand on the strained U.S. refinery capacity. California is currently the epicenter for use of natural gas as a vehicle fuel as both Compressed Natural Gas (CNG) and Liquefied Natural Gas (LNG). Currently, there are 40 plus LNG fueling stations and 160 plus CNG fueling stations in California. New York has a number of CNG fueling stations spread throughout the state from Long Island to Albany and west and ranks number two in the number of fueling stations. Utah, Oklahoma and Arizona also have a number of natural gas refueling stations and rank three, four and five respectively. Sixteen other states have fueling stations, but in very limited numbers, mostly associated with fleet vehicle operations rather than general public or independent heavy truck operators.

Most of these stations are CNG with the source of the natural gas from the installed pipeline network. LNG does provide supply to some CNG fueling stations, however. In these cases the station is usually configured to supply both CNG and LNG, but not always. The source of LNG is by truck shipment from peak shaving[ii], satellite or dedicated small-scale liquefaction plants (when compared to world class liquefaction plants associated with maritime transport of LNG). So-called “micro” natural gas liquefaction plants[3] also allow LNG to be supplied directly off the pipeline. Additionally, there are commercially available compressor systems intended to be installed in homes that have natural gas service that allow a vehicle to be filled with CNG overnight ready for the next day’s travel / commute.

It is clear from this activity that the U.S. is poised to make a significant shift in highway transportation fuel from light distillates to natural gas, particularly in the case of fleet vehicle operation, if only the opportunity is seized. The switch from light distillates to natural gas is also applicable to railroad and marine as well. Norway has been the leader in switching vessels to natural gas with several natural gas fueled (LNG) ferries and LNG fueled offshore supply vessels in service. Additional ferries and LNG fueled RO/RO vessels are on order. In the U.S. a CNG powered passenger ferry was placed in service in Portsmouth, Virginia in 1995.[4,5] Much has been learned from that first conversion to natural gas.

The current emissions environment, with emphasis on CO_2 reduction and pending implementation of the U.S. coastal Environmental Control Area (ECA), EPA Tier III and IV engine emission requirements, IMO Tier III (ECAs only) requirements and concerns about ship emissions in port areas suggests the potential for adoption of LNG as a vessel fuel sooner than later. Port emissions concerns has led to the adoption of “Cold Ironing” of vessels while pier side in a few early adoption ports. Cold Ironing involves powering the vessel (electrically) from shore allowing for the vessel’s diesel alternator sets to be shut down. On the face this appears to be a reasonable solution and in certain cases it certainly is. Those specific cases involve vessels that make regular port calls to the same ports, such as cruise ships and those ports that have the electric grid capacity to support the additional load and also produce electric power from environmental (emission) friendly power sources such as hydro, nuclear and/or natural gas fueled generation facilities. It certainly makes little sense to secure a modern IMO tier II / EPA tier III generator set in preference to a less emission

[i] Henry Hub is the pricing point for natural gas on the NYMEX and is generally seen to be the primary price set for the North American natural gas market

[ii] Peak Shaving plants are used to store natural gas as LNG during low demand periods and allow high send out rates of re-gasified natural gas during needle peak demand periods.

friendly power source, such as older coal fired power plants. In that case the end result is more emissions than what the ship was producing and spending significant capital to accomplish this dubious effort. It should be pointed out that the EPA / IMO engine emissions requirements deal with NO_x and particulates and not with CO_2 in engine exhaust. Switching fuels addresses both issues in a meaningful way.

Another problem with cold ironing is the variances of required shipboard power. Ships can be set up for a wide variety of voltages and either 60 or 50 hertz power adding complexity to the supply of shore based power to a variety of ships calling at the port. Conversion of available shore-side power specifications to the specification required for different vessels will also add another layer of efficiency losses adding to additional CO_2 emissions to the carbon inventory.

A better solution, if only LNG where more readily available, would be to install an LNG fueled generator set (or dual / tri-fuel generator) on the vessel and switch to natural gas upon entering the ECA area. This can be accomplished on a retrofit basis or, in the case of new construction, might be extended to the propulsion engines as well allowing complete fuel switching upon entering the ECA, not only U.S. ECAs but those in other parts of the world as well.

Switching to natural gas for shipboard power generation upon docking, or better yet, entering an ECA would be a simple process and have far more benefit in emission reductions than the current cold ironing solution.

LNG HISTORICAL PERSPECTIVE

The first commercial application of LNG in the U.S. was as a method of storing natural gas for use during peak demand periods or "Peak Shaving". This was in Cleveland in 1941. This plant operated successfully until 1944 when a new tank, recently put in service, failed catastrophically due to brittle fracture of the low nickel content steel. This was the beginning of the commercialization of LNG and also the worst disaster involving LNG with a loss of life of 128 people. Had the tank been constructed of 9% nickel steel or other material with appropriate low temperature brittle fracture properties, this incident and loss of life would not have happened.

In 1959 the "Methane Pioneer" made its historic voyage from Lake Charles to Canvey Island, UK inaugurating the next phase in commercialization of LNG, marine transportation. Since then the primary commercial uses of LNG have been to provide for storage of and/or the marine transportation of natural gas from source to market.

In peak shaving operations, natural gas is pulled off of a pipeline supply during low demand periods, liquefied and then stored in tanks as a boiling cryogenic fluid. During high demand periods the stored LNG is re-gasified and returned to the pipeline to meet the natural gas peak demand. Peak shaving plants typically have low liquefaction capacity, but high send-out (vaporization) capacity

Satellite LNG plants are a derivative of peak shaving plants. The difference is that a satellite plant does not have liquefaction capability. LNG is shipped into the plant (usually by over-the-road truck), transferred to the tank and then re-gasified when needed into the pipeline system. Satellite plants can serve in a peaking mode or base load mode where they serve communities with natural gas that lack access to distribution pipeline connectivity.

The most significant use of LNG has been the marine transportation of natural gas. In this use, natural gas is liquefied at the source, loaded into LNG carriers, transported to market and offloaded into receiving terminal tanks, either shore-based or floating. From the tanks the LNG is re-gasified into the pipeline system for distribution to the ultimate end user. The LNG carrier and terminals effectively form a virtual pipeline. A recent evolution of the marine transportation of natural gas is the elimination of the receiving terminal (a concept proposed by the author and others decades earlier[6,7]). In this concept the LNG carrier is equipped with on-board vaporization and discharges warm gasified natural gas directly into the pipeline system through an offshore buoy system and sub-sea pipeline. A drawback to this approach is the additional time (often days) the LNG carrier sits idle, moored to the buoy, versus traditional approach of pumping the liquid to shore tanks. The basic model is the same, moving natural gas from source to market. LNG is the enabling technology for the transportation of natural gas over maritime routes.

The above commercial uses of LNG ignore the inherent value of LNG as a liquid fuel source, a relatively energy dense liquid that has tremendous application as a heavy transportation fuel in both overland and marine routes. A not to be forgotten benefit of using LNG as a transportation fuel is the lower cost of fuel.

Over the years, the use of LNG as a fuel source has been demonstrated in multiple transportation modes including rail, marine and road with success. LNG has not enjoyed wide adoption as a transportation fuel for a variety of reasons. Recently, emissions and a desire to shift away from crude oil derived distillate fuels have brought LNG as a transportation fuel back into consideration. It still represents, however, a small percentage of LNG operations, but one that is poised to see substantial growth in the near future.

The technical aspects of utilizing LNG as a transportation fuel are, for the most part, resolved. Heavy truck tractors, buses, refuse trucks, etc. can be ordered from the factory configured for LNG. On the marine side, medium speed engines in both dual fuel Diesel / Otto cycle and natural gas only, spark ignited, Otto cycle engines are available and have solid installation and operational experience on a variety of vessels. The significant barrier to large-scale adoption of LNG as a transportation fuel is an effective delivery system / infrastructure.

The U.S. is blessed with an extensive pipeline system with an ability to deliver natural gas throughout the country. In order to make LNG available as a high-energy transportation fuel, however, relatively small-scale liquefaction plants are required at the point of use to take the gas off the pipeline, pre-treat as necessary, and liquefy the gas. On site bulk storage and local and/or regional distribution of the LNG is then required to the vehicle fueling point, be that land based or marine. Currently, this is the approach to providing a large portion of the LNG utilized in the Port of Los Angeles for the fueling of LNG fueled drayage tractors in the port area and other fleet vehicle uses.

For many areas of the country this is the only option. The U.S. also has additional, existing LNG infrastructure that can be leveraged to allow for the marine transportation of LNG in significant volumes, greatly facilitating the adoption of LNG as a transportation fuel. There are a number of LNG import terminals on the East and Gulf coasts. These terminals can be used to back feed LNG to a coastal or transshipment vessel. These smaller parcels of LNG can then be delivered to port areas as needed to provide LNG for not only traditional local gas distribution companies, potentially freeing capacity on interstate pipelines, but also for use as a transportation fuel for both land based and marine modes.

In the short term, existing LNG import terminals can provide the LNG for areas accessible to a suitable short sea LNG carrier. An argument against this approach is the extensive indigenous natural gas resources in the U.S. Why use imported LNG when we have significant reserves available and an extensive pipeline infrastructure to deliver natural gas to the end user? The answer to that is quite simple. It is already LNG. The additional steps of pretreatment and liquefaction of pipeline gas are not required. The cost of liquefaction is already included in the delivered cost to the import terminal. To be clear, pipeline-supplied gas will continue to play a major role particularly, in areas not served by navigable waters. But, where a marine highway exists, LNG sourced from import terminals can play a significant role.

Using pipeline gas is an obvious choice for CNG applications. CNG is a clear choice for light vehicles and short-range fleet vehicles, such as taxis. Inner city buses are candidates for either CNG or LNG. This is due to the relatively low energy density of CNG compared to LNG or light distillate fuels, reducing the effective range and increasing refueling periods. With heavier vehicles and longer-range requirements, such as for marine vessels, trains, etc. the higher energy density of LNG is a clear choice. Producing LNG from pipeline gas will require pre-treatment and liquefaction and then transportation to the distribution facility from the liquefaction facility. In many areas of the U.S. this is the only practical choice.

Areas of the U.S. that are accessible by the marine highway system, however, can benefit from LNG availability in a reasonably short and assured time frame by using a Short Sea LNG carrier (S^2LNGC) and the existing LNG import terminals. This capability can be put in place relatively rapidly. Critical path to implementation will be defined by permitting and vessel construction.

When or if recent gas discoveries in the U.S. fully materialize, the time may come when some of the existing import terminals are retrofitted with liquefaction plants. At least one Gulf Coast import terminal is actively pursuing the addition of liquefaction capability to their LNG import facility and has received regulatory approval for LNG export. The potential is there for the source for LNG shifting from imported LNG to domestic LNG. Liquefying at a larger capacity facility can be expected to be more cost effective due to economy of scale than multiple small scale, low capacity liquefaction systems scattered in demand areas pulling off the gas pipeline infrastructure of Local Distribution Companies (LDC). The LDCs and available pipeline capacity (particularly during peak demand periods) may or may not be able to handle the additional demand. A further benefit of a marine highway based LNG distribution system is the ability to supplement existing pipeline capacity by supplying LDCs with additional gas supply to assist in meeting the expected growing demand for natural gas. With the alternate source of natural gas, LDCs may avoid having to upgrade or install additional pipeline capacity. Additionally, the LDC may be able to release underutilized, purchased pipeline capacity, reducing costs for their customers. This capacity can then be employed to serve areas not convenient to the marine highway system.

SHORT SEA LNG CARRIER

In order to facilitate the expanded use of natural gas and more specifically LNG as a transportation fuel, a practical and economic Short Sea LNG Carrier (S^2LNGC) is required. This vessel can either be a ship form, as are currently in operation in Norway and Japan, or a barge based system, such as an Articulated Tug / Barge (AT/B) as has become a common vessel solution in the U.S. domestic trade, although not limited to the U.S. exclusively.

Ship form S^2LNGCs vary in capacity from 1,100 m^3 to approximately 10,000 to 12,000 m^3. Currently there are no AT/B or barge based LNG carriers. A current LNG AT/B design, described herein, that is at contract design level has a loaded, cold capacity of approximately 13,000 m3.

There are numerous key factors that drive an LNG AT/B design in addition to the normal vessel design compromises. For service in the U.S. under Jones Act trade the Articulated Tug / Barge has become a vessel of choice in the bulk trades. There are many reasons for this from crewing, operational flexibility, construction flexibility, capital cost, etc.

Boil-Off Rate

One of the first things to consider for an LNG carrier is cargo boil-off management and control. This will then lead to cargo containment system considerations.

Modern LNG carriers, regardless of containment system, have contract cargo boil-off rates in the range of 0.10% to 0.15% per day of loaded volume. The boil-off rate is a contracted performance specification and depends on the quality of the tank insulation. Hand in hand to quality or performance of the insulation system is cost. If money is no object, the boil-off rate can be further reduced. There is a trade off of insulation thickness versus boil-off rate versus loss of cargo capacity. Thus, we come to the typical values of contract boil-off rate mentioned above. It would, however, be a mistake to consider typical contract boil-off rates of modern line-haul LNG carriers as appropriate to a S^2LNGC.

Contract boil-off rate is a function of heat leakage into the cargo tank from ambient conditions. The parameters are the thermal performance of the insulation, thickness of the insulation, the temperature difference between the temperature of the cargo (typically –260^{o}F (-162^{o}C)) and design ambient conditions. Since the delta T between any rationally selected ambient design condition and the cryogenic cargo temperature is so large, the choice of ambient design condition is less of an influencing factor. Insulation performance and thickness are obvious design factors, but when comparing boil-off rates of typical line-haul LNG carriers to an order of magnitude smaller capacity S^2LNGC, perhaps a less obvious factor is cargo tank surface area in comparison to tank volume.

Once the factors above are determined the heat leakage into the cargo tank can be calculated. The boil-off rate is determined by calculating the vaporization rate of the cargo as a result of the heat leakage rate. The vaporization rate is then compared to the loaded cargo volume over a 24 hr period to determine the boil-off rate, as it is typically stated. The amount of vaporized cargo per unit of time is also a critical value when consideration is given to handling the cargo boil-off. For a S^2LNGC of 13,000 m^3 LNG capacity (loaded volume based on relief valve setting), boil-off rates can be expected to be in the range of 0.30% per day to 0.50% per day, dependent on insulation system performance.

This may appear to fly in the face of boil-off rates on line-haul LNG carriers, but a comparison of tank surface area to loaded volume will make clear the underlying reason. Fig. 1 shows this comparison for both membrane tanks of 27,000 m^3, a spherical tank of 25,000 m^3 (typical of early generation of 125,000 m^3 LNG carriers) and IMO International Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk (IGC Code) type C cylindrical pressure vessel tanks of approximately 7,000 m^3, 3,300 m^3 and 2,000 m^3 capacity. The ratio of surface area (direct correlation to heat leakage for a given insulation system and ambient conditions) to loaded volume explains the disparity between vessel boil rates for similar tank insulation systems.

Containment System

There are a variety of containment systems to choose from. In the broadest categorizations in accordance with the IGC Code, there are: 1. Membrane and semi-membrane; 2. Independent tank type A; 3. Independent tank type B; and 4. Independent tank type C. Type A tanks are generally of prismatic shape but are not designed to leak before failure criteria and, therefore, require a full secondary barrier. Type B tanks are freestanding tanks that are designed under a leak before failure criteria and, therefore, only require a partial secondary barrier. These tanks are available in both prismatic and spherical shapes. Type C tanks are based on recognized pressure vessel standards and require no secondary barrier.

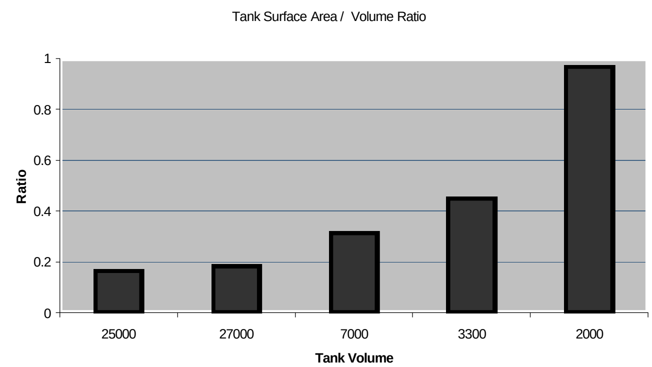

Fig. 1 Cargo Tank Surface Area vs. Tank Volume

Membrane, type A and type B tanks are generally pressure limited to just slightly above atmospheric. Whereas type C tanks can be designed and certified to pressures above atmospheric, which is quite typical for pressure, versus refrigerated, LPG carriers. Type A tanks, being prismatic in shape provide good volumetric fit to hull structure for cargo tankage, as do membrane and prismatic type B tanks. Currently, type A tanks have fallen out of favor in preference for prismatic type B tanks largely due to sophisticated analysis tools and fabrication capabilities. The original Conch prismatic aluminum tank is an example of a type A tank. Current type B tanks offered include the SPB prismatic aluminum tank and the large spherical tanks (the spherical tanks are, in effect, type C tanks but due to their size, are designed and certified as type B). Although there is a significant advantage in volumetric efficiency for membrane and type B prismatic tanks, the operating pressure limitation, Maximum Allowable Relief Valve Setting (MARVS), is a severe limitation with regards to handling cargo boil-off for a S^2LNGC, which will be discussed in a later section herein.

Similarly, spherical tanks would severely limit forward visibility from the tug's wheelhouse and drive the tug's proportions to extreme in an attempt to provide adequate visibility forward. Although the ratio of surface area to volume, and therefore boil-off rate, is geometrically optimum, the volumetric efficiency when compared to a barge hull form is the most inefficient.

Cylindrical pressure vessel tanks with a design pressure to allow a MARVS of 40 to 60 psig has been found to be a reasonable compromise of availability, pressure capability and volumetric efficiency. Fig. 2 illustrates the cargo unit midship section with cylindrical pressure vessel tanks.

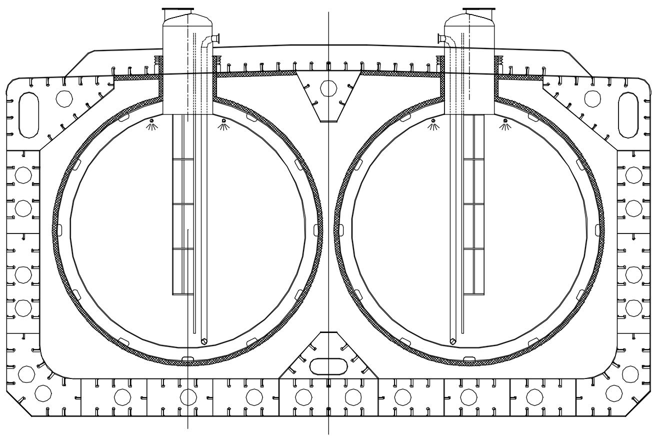

Fig. 2 Cylindrical Tank Midship Section

Another possibility to improve volumetric efficiency is the concept of bi-lobe or even multi-lobe pressure vessel cargo tanks. Bi-lobe tanks are quite common on LPG vessels. If the vessel is not beam limited, i.e. to accommodate specific ports, locks, etc., the use of bi-lobe tanks can significantly increase capacity without driving the depth of the S^2LNGC cargo unit to extremes. If the depth of the S^2LNGC barge hull is maintained and bi-lobe tanks considered versus cylindrical tanks, the cargo volume could be increased significantly as illustrated in Fig. 3 by the cross hatched additional area. The beam of the S^2LNGC barge will increase approximately 40% for the same basic cylinder diameter.

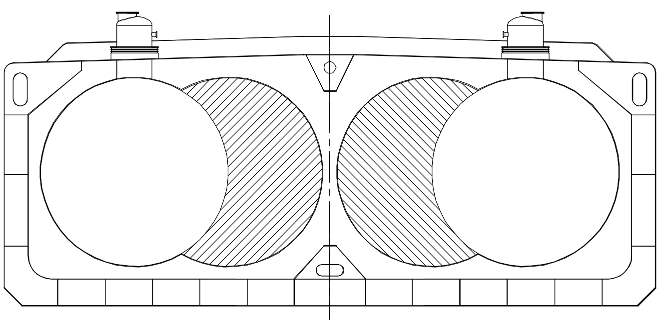

Fig. 3 Bi-Lobe Tank Midship Section

The choice of pressure vessel head design will also have an impact on cargo capacity. As mentioned above, the spherical shape of hemi-spherical heads, provides the best ratio of surface area to volume and, therefore, the least boil-off rate of the cargo. The use of elliptical heads or tori-spherical heads, however, will provide a slight increase in tank volume for the same overall length of the cargo tank improving volumetric efficiency slightly. Generally a depth to diameter ratio of 2:1 is provided under the ASME pressure vessel code.

As can be seen in figure 4, an elliptical head can provide approximately 3.5% tank volume increase over a hemi-spherical head. The tori-spherical head is based on the combination of geometric shapes of a torus and a sphere. The tori-spherical head can provide an approximate 4.7% increase in tank volume over a hemi-spherical head.

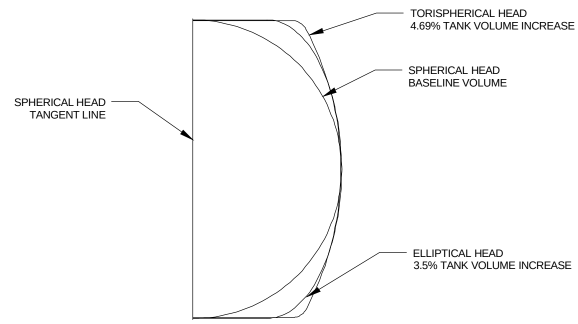

Fig. 4 Cargo Tank Head Configuration Comparison

It might be considered a clear choice to use either the elliptical head or tori-spherical head vs. a hemi-spherical head for the added volume to the cargo tank. Unfortunately, there is a thickness penalty to the use of the alternate head shapes. The tori-spherical head will require approximately 3.5 times the material thickness for equivalent tank pressure rating. That, of course, translates to added tank weight and cost.

There are three acceptable choices of material for Type C LNG tanks for LNG service. 5086 Aluminum, 304 stainless steel and 9% nickel steel. Any of these materials is acceptable and the choice has more to do with material cost, fabrication cost and fabricator capabilities. Recent gas carrier designs, in a comparable cargo capacity, have utilized 304 stainless steel for the cargo tanks. This has been based on material and fabrication costs as well as required minimum design pressure under the IGC Code. Table 1 examines the required minimum tank design vapor pressure for a 13,000 m^3 S^2LNGC for each acceptable tank material.

Table 1. Tank minimum design pressure

Tank Material	**Minimum Design Vapor Pressure**
304 Stainless Steel	39.2 psig (2.7 bar)
9% Nickel Steel	62.4 psig (4.3 bar)
5083 Aluminum	52.5 psig (3.6 bar)

The liquid pressure, including dynamic liquid loads, is added to the appropriate minimum design vapor pressure to determine the design pressure under the ASME pressure vessel code.

The method of supporting the cargo tanks must be given careful consideration. As a general rule, two supports or saddles should support horizontal pressure vessels longitudinally. This is to prevent the transfer of bending moments and hull deflections to the tank from the hull resulting from still water and wave induced hull bending. This should not be taken to remove a greater number of supports / saddles from consideration. Compressive stresses in the tank shell resulting from longitudinal bending moments in the tank will drive the required shell thickness higher. Increasing the number of saddles will allow for reduced shell thickness, but consideration must be given to localized bending moment increases resulting from the loading and unloading of the saddles resulting from hull bending.

The mounts must be configured to accommodate the shrinkage of the tank when in the cold condition and also to provide restrained motion in the global transverse and longitudinal directions. The tank must also be restrained in the vertical direction to prevent the tank from floating in the case of a hull breach. Fig. 5 illustrates a saddle configuration utilizing two principal tank supports near the ends of the cargo tank that provide vertical (including anti-floatation) support and transverse restraint. These saddles are un-restrained longitudinally allowing the tank freedom to shrink as it is cooled to operational temperature. The center mount, however, is un-restrained in the vertical direction but restrained transversely and longitudinally. The tank dome is, therefore, held in relative position as the tank is cooled. In the case of three saddles supporting the tank vertically, the center mount would be configured to provide restraint transversely, longitudinally and vertically.

jacketed. This is correct only so far as a type C tank might be vacuum jacketed, which is the preferred approach for comparatively much smaller road transport tanks, LNG fuel tanks, containerized cryogenic tanks, shop fabricated land based tanks, etc. In the case of type C tanks in a S^2LNGC, vacuum jacketing is not practical or necessary.

In the case of the only LNG barge built and operated in the mid seventies, tank insulation was simply powdered perlite filled in the space between the tank and the inner hull. This is a minimally effective insulation system in comparison to the performance of modern insulation systems. This approach also has the significant draw-back of having to remove the perlite, a very fine powder, to do any inspection or accomplish repairs. In light of insulation systems currently available, a perlite filled hold space is not consider an acceptable insulation system.

Rigid foams of various compositions are the preferred choice of insulation systems. Recently, concerns have been raised of the safety of foams as an LNG tank insulation system given the flammability of polyurethane and other typical rigid insulation foams. The theory is that an LNG pool fire resulting from the breach of a single cargo tank will cause the insulation on the remaining tanks to combust exposing the other tanks directly to the fire. The postulated result is a cascading failure of the undamaged cargo tanks. A recent study has been accomplished to specifically address this failure theory.[9] This study concludes that failure of adjacent cargo tanks as a result of exposure to a pool fire and the loss of the insulation system is not a credible scenario. Notwithstanding the results of the study, an insulation system that first, will not combust and second, will provide

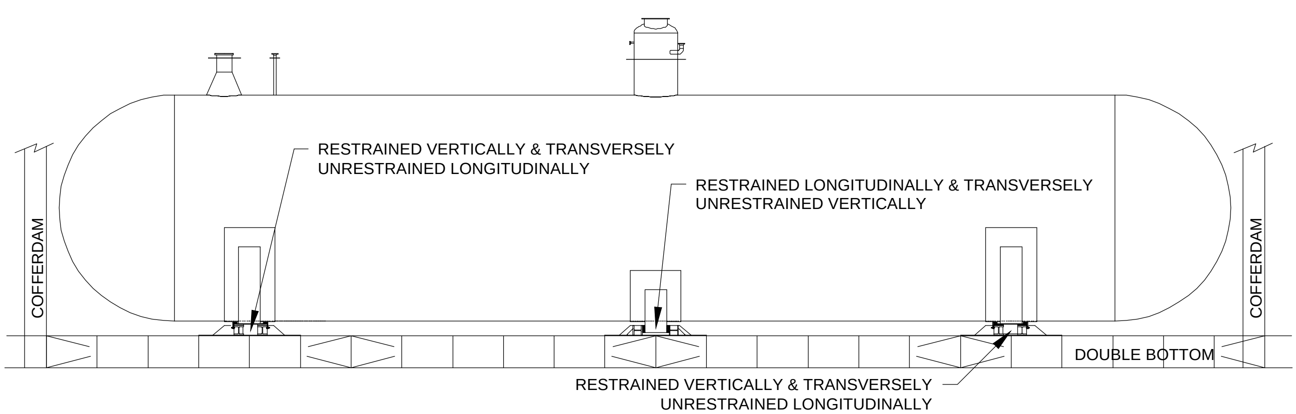

Fig 5 Cargo Tank Support and Restraint

Insulation System

As has already been discussed, the insulation system has everything to do with the achieved boil-off rate. In a recent article[8] the author describes type C tanks as being vacuum

thermal, fire, protection to the cargo tank is highly desirable. Fortunately, “aero-gel”[10] technology provides an insulation system that not only provides improved low temperature performance, reducing cargo boil-off rate, but also provides fire protection equivalent to an A-60 bulkhead.

A full description of aero-gel technology is beyond the scope of this paper. In brief, however, aero-gels have a very low bulk density and are highly effective insulators for both low and high temperatures. Aero-gels are manufactured by extracting the liquid component of a gel and replacing it with a gas by a process of supercritical drying. Current technology provides for aero-gels to be fabricated into flexible blankets, making an ideal thermal insulation system. Aero-gel blankets are thermally 2 to 3 times more efficient than competing insulating materials.

The improved thermal conductivity allows the insulation system to be substantially reduced in thickness and still provide for a design boil-off rate of 0.30% per day. This reduction of insulation thickness allowed an increase in total cargo capacity from nominal 11,000 m3 to 13,000 m3 while maintaining the cargo tank hold dimensions and, therefore, the barge principal dimensions for the S^2LNGC described herein.

Boil-Off System

Control of cargo boil-off is a critical aspect of an LNG carrier's design and no less so in a S^2LNGC. Traditionally, two methods of boil-off control have been utilized in line-haul LNG carriers. The primary method was to burn the gas in the carrier's boilers. The resulting steam is used either for propulsion, or the steam pressure is reduced and de-superheated to condenser conditions and dumped directly to the main condenser. In this manner, as long as the systems are operational, the boil-off gas and, therefore, cargo tank pressure, can be controlled independent of energy demand requirements of the carrier. This is a critical factor for cryogenic tanks with MARVS near atmospheric pressure, typical of all but type C containment systems.

The second method of boil-off / cargo tank pressure control, is to vent the gas to the atmosphere via a vent valve independent of the cargo tank relief valves. This is highly undesirable for any number of obvious reasons, but is preferable to lifting the cargo tank relief valves.

These two methods of cargo tank pressure control are typical of legacy LNG carriers. Recent developments, however, have seen the installation of re-liquefaction plants to re-liquefy the boil-off gas and return it to the cargo tank. Boil-off control is now independent of the propulsion and/or load demands of the carrier and the ability and need to dispose or dump excess energy is eliminated. This is used on vessels where low speed diesels burning residual fuel oils are fitted. The economic benefit is the ability to deliver 100% of the loaded cargo and to burn what was anticipated to be lower cost residual fuel oil in low speed diesel engines. Interestingly, recent developments in current / anticipated environmental regulations, carbon trading, ECAs, etc. may make the decision to utilize residual fuels over natural gas boil-off premature. With regard to fuel cost it is just as likely that the requirement for low sulfur fuel and increased natural gas supply will remove any pricing advantage of residual fuels. Similar to burning the boil-off in the carrier's boilers, the back-up boil-off control and tank pressure control is by controlled venting as the liquefaction systems are independent of the carrier's energy demands. Controlled venting is only to be employed in the event of failure of the liquefaction systems.

Another recent approach has been to employ gas-burning engines, either Diesel/Otto cycle (pilot fuel ignited) or Otto cycle (spark ignited) engines, to utilize the boil-off gas to supplement the energy demands of the carrier. Since the control of boil-off / tank pressure is now dependent on fuel demands of the engines and there is no ability to dump excess energy as in the steam dumping system of legacy carriers, another method of consuming boil-off gas is needed, in addition to venting, for the situations when the carrier's power demands are below the energy available from natural boil-off. This is often provided by the installation of gas combustors, which burn the boil-off gas in a contained flare and exhaust the combustion gas to the atmosphere. Controlled venting is still an option should all else fail prior to allowing the cargo tank relief valves to lift.

Type C tanks are required to be designed for a minimum pressure based on the requirements of the IGC Code. This depends on tank dimensions and material. For horizontal cylindrical tanks, tank bending moments will typically drive the shell thickness above that required to accommodate minimum design pressure. In any case, type C cylindrical tanks can accommodate natural boil-off simply by allowing the cargo tank to increase in pressure over time as the cargo vaporizes due to heat leakage through the insulation system. Hold times can be 30 days or longer, depending on insulation effectiveness, before the tanks must be vented to prevent the relief valves from lifting. The IGC Code is silent as to required hold times leaving it to the Administration. U.S. Coast Guard regulations 46 CFR 154.703 requires a hold time of 21 days.

Unfortunately, along with the pressure increase, the cargo equilibrium temperature also increases as heat leakage through the insulation raises the cargo temperature as boil-off is suppressed. This will be problematic, depending on where the cargo is being discharged, and presents an additional safety concern if the equilibrium temperature and pressure is allowed to significantly increase over normal LNG equilibrium conditions.

If the LNG, which is now at a higher equilibrium temperature and pressure is discharged into a tank containing LNG at near atmospheric pressure equilibrium conditions, the higher equilibrium LNG will rapidly vaporize causing an increase in vapor that cannot be handled by the receiving terminal's vapor systems. Additionally, roll over may be a potential problem if the LNG stratifies in the tank. Both situations are unacceptable and potentially hazardous. If the S^2LNGC will be discharging into tanks at near atmospheric pressure, boil-off handling on the carrier by allowing the tank to pressurize is not an acceptable approach. It is critical that the tanks on the carrier be maintained at a pressure to deliver the cargo at acceptable equilibrium conditions for the receiving facility.

If, however, the S^2LNGC is delivering to a facility where the LNG is held at higher pressures in pressure vessel tanks, then higher delivery pressure equilibrium pressures may be acceptable. Nonetheless it is important for the cargo to be delivered at equilibrium conditions that the receiving facility is able to handle safely and in the normal course of operation.

There is also a safety concern with LNG at equilibrium conditions resulting from pressure significantly above atmospheric that should not be ignored. An aspect of LNG at near atmospheric pressure equilibrium conditions is the manner in which it vaporizes should it be catastrophically released, i.e. as in a tank breach. Such a rapid release of the cargo results in the rapid vaporization of the LNG. The vaporization is the result of heat input into the liquid from the surroundings. As the LNG equilibrium temperature corresponds to near atmospheric pressure, a rapid pressure drop does not contribute to the vaporization rate. In the case of LNG at an equilibrium condition associated with a higher pressure, the rapid pressure drop increases the rate of vaporization, increasing the size of the vapor cloud at the instant of release of the cargo. Although the total mass of vapor release will be the same, the time frame for release will be significantly shorter. In addition, where a small breach of a cargo tank may provide a limited cargo release over time for a cargo at near atmospheric pressure equilibrium conditions, the same size breach can be expected to release significantly more vapor in a shorter period of time for LNG at equilibrium conditions associated with higher pressures, and must be considered carefully when analyzing safety aspects. A recent opinion column in Marine Technology declared a key safety factor of LNG was that "LNG is not stored under pressure…"[11]. Significant pressure rise as a method of boil-off control must be considered in light of overall safety. Where the voyage length is short, however, pressure build is a viable approach to boil-off, as the overall equilibrium temperature of the cargo will not increase materially. Pressure build is used in several successful small LNG carriers.

Clearly, an effective S^2LNGC must have a system to handle natural boil-off of the cargo to enable the cargo to be delivered at specified equilibrium conditions to the receiving terminal(s). A combination of tank pressurization, combustion in engines, liquefaction and/or burning in gas combustor units can be considered.

Cargo Manifold, Loading and Discharge

It is desirable for the S^2LNGC to be able to load at existing LNG import terminals without the necessity for the construction of a dedicated loading berth. There are a number of issues to be considered. The most obvious is the operating envelope of the loading arms at the candidate terminal. The manifold on the S^2LNGC cargo unit must present the flanges within the operating envelope. The manifold flange and platform on the cargo unit of the S^2LNGC must also be able to handle the loads imposed by the Powered Emergency Release Connection (PERC) under an emergency release situation. A concept manifold is shown in Figure 6.

The S^2LNGC barge must also be able to securely moor to the terminal as well. Evaluation of mooring points, number of mooring lines, fendering and flat of side with respect to

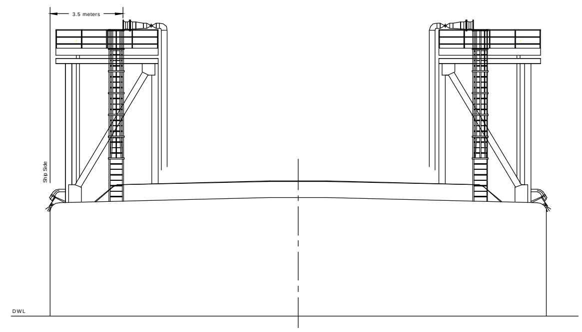

Fig. 6 High Cargo Manifold

positioning the manifold relative to the loading arms is critical.

Typical receiving terminals are fitted with 4 to 5 - 16" diameter loading arms, 3 to 4 liquid arms and 1 vapor arm. The S^2LNGC barge can be loaded, depending on desired time to load, with one 16" diameter liquid arm. A connection will be required for vapor return during the loading process. The high manifold, therefore, at a minimum, must have two 16" diameter ANSI presentation flanges, one for liquid and one for vapor.

The terminal must also be able to supply LNG to the manifold. This is a reverse direction from the normal flow direction of an import or receiving terminal. In many cases the terminal is fitted with the capability to circulate LNG to the pier to keep piping cold ready for the next ship arrival in which case, it is a relatively simple matter to reverse flow LNG to a S^2LNGC. Each terminal is unique and may require modifications to allow loading of a vessel versus normal vessel discharge operations.

The high manifold also provides for the ability for the S^2LNGC to load from a line-haul LNG carrier, allowing for lightering and distribution of LNG to ports not accessible by the large line-haul carrier.

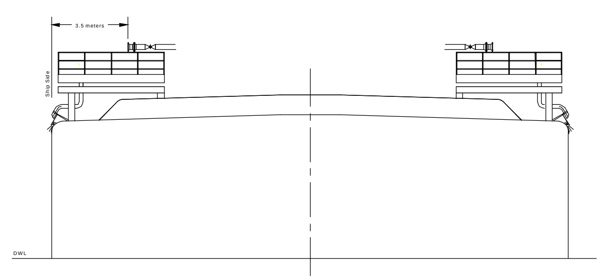

Fig. 7 Low Cargo Manifold

A dedicated S^2LNGC receiving terminal would be designed for the vessel and, therefore, be configured and dimensioned differently. The number and size of the connections will be reduced and the manifold will be located at a minimum working height above the deck as illustrated in Fig 7.

The spacing between manifold flanges and the distance from ship's side will be in accordance with the Oil Company International Marine Forum (OCIMF) standards for gas carriers.

13,000 m^3 SHORT SEA LNG AT/B

A 13,000 m^3 LNG Articulated Tug / Barge design based on the foregoing considerations has been developed. The principal particulars for the vessel(s) follow.

Combined S^2LNGC AT/B	
LOA	591ft – 1 inch (180.2 m)
Speed	12 knots

S^2LNGC Tug	
LOA	121 ft – 0 inch (36.9 m)
Beam	42 ft (12.8 m)
Operational Draft	19 ft – 6 inch (5.9 m)

S^2LNGC barge	
LOA	516 ft – 4-1/4 inch (157.4 m)
Beam	78 ft (23.8 m)
Operational Draft	20 ft. (7.2 m)
Depth	40 ft. – 7 inch (40.6 m)
Cargo Capacity (100% Cold)	13,352 m^3
Loaded Cargo Capacity	13,000 m^3

POSSIBLE ROUTES

On the East coast there are three LNG import terminals; one in Boston, Massachusetts; one in Cove Point, Maryland in the Chesapeake Bay and one in Elba Island, Georgia. Of these terminals, the Cove Point and Elba Island terminals are in excellent position to serve an LNG Short Sea Route covering New England to Florida.

There are also a number of satellite and peak shaving plants that are located adjacent to S^2LNGC accessible waterways. Specifically: Fall River, Massachusetts; Providence, Rhode Island; Philadelphia, Pennsylvania and Chesapeake, Virginia. There is also a peak shaving plant near Charleston, South Carolina that is potentially accessible. Table 2 lists the one way voyage distances from the Elba Island LNG terminal to possible delivery ports / facilities. Table 3 lists the one way voyage distances from the Cove Point LNG terminal to possible delivery ports / facilities.

Table 2 Elba Island LNG Terminal

Jacksonville, Fl	150 nautical miles
Charleston, SC	120 nautical miles
Providence, RI	800 nautical miles
Tampa, FL	822 nautical miles

If this existing infrastructure can be leveraged, an LNG distribution network could be established in a relatively short period of time facilitating a variety of expanded opportunities for LNG as a transportation fuel in addition to supplementing existing pipeline capacity or trucking routes, as in the case of satellite plants such as the plant in Providence, Rhode Island.

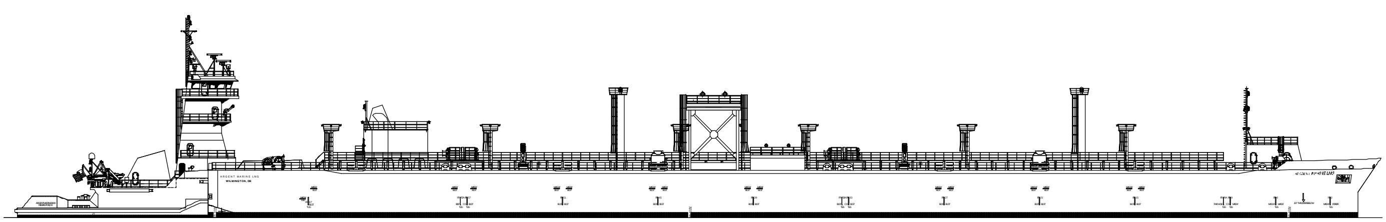

Fig. 8 13,000 m3 S2LNGC Combined Unit Outboard Profile

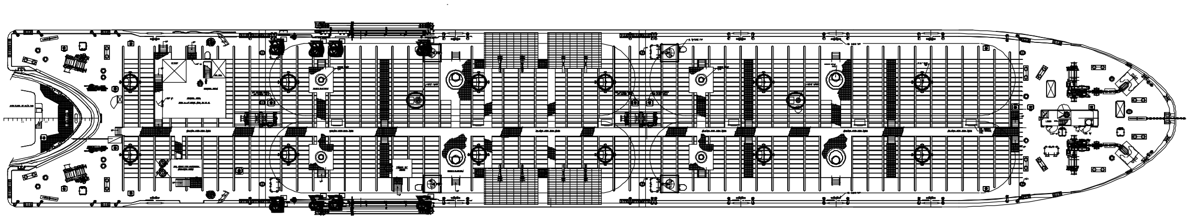

Fig. 9 13,000 m^3 S^2LNGC Cargo Unit Main Deck Plan

By utilizing existing plants as receiving terminals the Short Sea LNG trade can be boot-strapped by leveraging existing gas demand to keep utilization of an S^2LNGC at economically viable levels while LNG fuel demand grows.

Table 3 Cove Point LNG Terminal

Philadelphia, PA (ocean)	331 nautical miles
Philadelphia, PA (C&D Canal)	140 nautical miles
Chesapeake, VA	110 nautical miles
Providence, RI	490 nautical miles
New York, NY	380 nautical miles

There is no limitation on establishing receiving terminals specifically for distribution of LNG fuel. There is an obvious bootstrap problem for LNG fuel demand to increase before the operation moves into a viable cash flow regime. Further opportunity exists where conversion of a power generation facility to natural gas might be combined with an LNG fuel distribution facility to improve utilization rate of the S^2LNGC.

Although there is an obvious advantage to short route distances, moving LNG from Gulf Coast import terminals to Florida and the East Coast should not automatically be discounted. AT/B performance is such that longer routes are potentially viable which mirrors current distillate fuel routes in operation. Similarly, short sea LNG routes on the West coast might also prove viable, although there is limited existing infrastructure to leverage as compared to the Gulf and East coasts.

TRANSPORTATION ECONOMICS

Assumptions

Supply terminal – Cove Point
Delivery port - Philadelphia
Loaded voyage route – Ocean route via Cape Henry
Ballast voyage route – C & D Canal
Service speed – 12 knots
Load pressure – 15.4 psia
MARVS – 30.0 psig
Boil-off rate – 0.40%/day
Cargo capacity 100% cold condition – 13,352 m^3
Gas heating value – 1034 BTU/scf
Gas to liquid ratio – 618:1
No 2 diesel heating value – 129,500 BTU/gal

Delivered Volumes

Delivered volume / voyage– 12,382 m^3
Delivered volume / annum – 1,067,538 m^3
Delivered energy - 24,105,017 decatherms / year

Comparative Fuel Cost

In order to compare delivered price of LNG as a transportation fuel to the cost of No 2 low sulfur diesel, it is common to equate the fuels on an equivalent energy basis. Based on the assumptions provided above, 1.516 gallons of LNG has the equivalent energy content of 1 gallon of diesel.

According to the U.S. Energy Information Administration (EIA), the average Henry Hub price for natural gas in August of 2010 was $4.221/mmBTU. The average cost of No 2 low sulfur diesel to industrial customers during the same period was $2.50/gal (excluding taxes).

On a Diesel Gallon Equivalent (DGE) basis the delivered cost of LNG to the Port of Philadelphia would be approximately $1.84 DGE. This compares favorably to the diesel cost of $2.50/gal for the same period. Compressed Natural Gas (CNG) is available in the Philadelphia area in a limited capacity. On a DGE basis price during the same period the CNG price ranges from $2.00 to $2.50 DGE. LNG as a transportation fuel is not available in Philadelphia so direct comparisons are not possible. In California, however, where both LNG and CNG are available on a retail basis the prices on a DGE basis are comparable between CNG and LNG.

The above clearly indicates that providing LNG as a transportation fuel by a short sea marine highway transport scheme from existing terminals is competitive with current methods. There are, obviously, many factors that will influence the delivered cost of LNG for use as transportation fuel not the least of which are commodity and market pressures

THE FUTURE

There is an argument that the U.S. should focus solely on domestic gas reserves. There are obvious reasons for this and it is well recognized that there are significant economic, political and security reasons for limiting energy imports, be it oil or gas. In the short term, however, imported LNG can be effectively leveraged to speed up the adoption of natural gas as a transportation fuel. The environmental benefits are clear and well documented. The technology to implement the change, including a suitable S^2LNGC, is non-developmental, unlike other transportation alternatives being considered such as fuel cell and electric vehicles (requiring significantly improved battery performance).

What is lacking is the ability to establish an LNG infrastructure in a timely fashion to encourage switching from distillate and residual fuels to natural gas.

Looking forward, the time may come where domestic sources of gas are developed to the point where current LNG import terminals actually install liquefaction plants and become sources of LNG for a developed domestic LNG fuel market. At least one facility has taken the initial steps in that direction. If domestic gas reserves develop, largely due to anticipated shale gas development, the investment in LNG distribution infrastructure is not lost, it just shifts the source of LNG from imported to domestically produced LNG. This would allow a future shift away from imported LNG to domestic sources. Until, however, an effective LNG infrastructure can be established, the use of LNG as a competitive, low emission alternative fuel will lag and an opportunity to make meaningful emission reductions and reduced dependence on oil (foreign or domestic) will be delayed or lost.

Furthermore, as fuel cell technology continues to develop, natural gas is a primary candidate fuel. Therefore, as internal combustion engines begin to give way to fuel cell technology, the LNG infrastructure developed will continue to play an important role in powering society into the future.

CONCLUSIONS

An effective Short Sea LNG Carrier design based on state of the art Articulated Tug / Barge technology has been developed for domestic US and non-domestic service. By leveraging existing LNG import, peak shaving and satellite terminals a significant LNG infrastructure can be developed in the near term allowing early adoption of the use of LNG as a heavy transportation fuel, both on-road and marine. There are no developing technology obstacles to be overcome.

Provided LNG suppliers are prepared to enter the developing market for LNG fuels, LNG can be in place in and around S^2LNGC accessible ports in a relatively short period of time. Significant reductions in emissions can be achieved sooner than later with long term benefit. No other approach to emission technology can achieve the benefits of simply switching to natural gas as a transport fuel in as short a time period and as economically. Potential fuel cost and maintenance savings will provide for return on investment to switch to natural gas fueled engines versus other emission reduction strategies.

The benefits of establishing a short sea LNG trade as discussed herein, are principally focused to transportation fuel. Clearly electric generation plants that are water accessible can be switched from firing coal, residual and distillate fuels to natural gas. New standby power plants to back up solar and wind farm electric generation could also be supplied by LNG delivered by the marine highway system. Additionally there are numerous LNG peak shaving and satellite plants that are either waterside or near waterside that can be fed by an S^2LNGC supplementing existing pipeline capacity and allowing that capacity to be diverted to support gas demand increase in land-locked areas.

If these potential markets are combined, an effective short sea LNG trade can be economically viable even before the LNG fuel market fully develops.

REFERENCES

[1] Rolls Royce / Bergen Engines product information
[2] Exhaust Emissions from a CNG Ferry, US Maritime Administration (MARAD), National Maritime Resource and Education Center, Workshop on Maritime Energy and Clean Emissions, January 29, 2002.
[3] Hamworthy Gas Systems AS Micro LNG product information
[4] December 1999, Workboat Magazine, pp 104-105
[5] Worlds First Natural Gas Powered Passenger Ferry Vessel, Patrick Hughes, SNAME Hampton Roads Section, April 7, 1994
[6] Van Tassel, G.W., Boylston, J.W., "An Economic System for the Liquefaction, Transportation and Re-gas of Natural Gas Using Surplus LNG Carriers", S.N.A.M.E., Maritime Innovation - Practical Approaches '84.
[7] Van Tassel, G.W., Strohman, J.R., “Concept Proposal for the Transportation and Re-gasification of Liquid Natural Gas”, Argent Marine Operations, Inc., 1996
[8] Teo, T.C.S., The LNG Containment System, Marine Technology, April 2010, Society of Naval Architects and Marine Engineers, pp 21-27
[9] Wuersig, Gerd-Michael, Germanischer Lloyd Group, et al, Effects of Enveloping Pool fires on LNG Tank Containment Systems, GasTECH Conference 2009
[10] Cryogel Z product information, Aspen Aerogels
[11] Cooper, Bill, Better Public Understanding, Marine Technology, April 2010, Society of Naval Architects and Marine Engineers, p 8