FLOATING LNG PLANTS – SCALE-UP OF FAMILIAR TECHNOLOGY

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ABSTRACT

Increasing costs of onshore base load LNG plants and technology developments in offshore LNG storage and transfer have resulted in offshore LNG production now being commercially viable, even at plant capacities of 1 to 2 million tonnes per annum.

At these LNG production rates, floating plants will use liquefaction processes based on turbo-expanders to generate the refrigeration for liquefaction. This technology is conventional for cryogenic liquefaction plants and used onshore for small-scale LNG production. It gives many important advantages for a floating facility. A primary consideration is the inherent safety of the process but it is also the best process solution in terms of simplicity, operability, small footprint and low topsides weight. This means both overall project cost and schedule to first LNG production can be competitive with base load LNG production onshore.

Costain first developed a floating LNG plant design nearly thirty years ago, from experience in designing and building onshore liquefaction plants using turbo-expanders. Since then Costain has undertaken many front-end designs for floating LNG projects.

Floating LNG plants will be much larger than the existing LNG plants that use turbo-expanders and this introduces significant new technical, engineering and safety considerations. The configuration of the refrigerant compression system and the associated compressor drivers is a particularly key area. The need for marinization and the interfacing of the topsides with the hull are also novel aspects of liquefaction plant design.

This paper will highlight the techno-commercial issues associated with floating LNG and how they are being resolved.

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INTRODUCTION

LNG Shortages from Conventional Sources

Increasing demand for LNG has led to the upgrading of existing import terminals and new regasification facilities in the USA, Western Europe, India and China whilst, in parallel, deliveries of new LNG carriers have recently been at record levels. Several new LNG plants should start-up in 2009 but so much proposed LNG production capacity has not materialized that a shortfall in worldwide LNG production of up to 150 million tonnes per annum (mtpa) is expected by 2012.

Lack of investment in new LNG production has been partly due to a shortage of sufficiently large gas fields near shore and lack of suitable plant sites. Some leading LNG producing nations have recently declared moratoria to maintain their indigenous gas reserves for domestic use. Final Investment Decisions (FID) on projects have been postponed due to escalating plant costs (due to shortages in raw materials and limited human resources in engineering and construction firms). It is unlikely that many delayed or postponed LNG projects will be implemented soon (1).

The Potential of Floating LNG

The difficulties with onshore LNG projects have renewed interest in offshore LNG production. Studies over the last thirty years identified the main technology developments necessary to make offshore LNG production feasible (2). As well as process technology and plant design issues, advances in offshore LNG transfer and storage have been essential to the viability of offshore LNG. Developments in LNG transfer at sea have advanced to a point where several suppliers have commercial systems available and transfer of LNG at sea has been demonstrated successfully. A decade ago only one LNG storage system was proven for partially full operation at sea (i.e. robust enough to stand sloshing when partially full) whereas today several LNG storage systems are certified and all the main LNG shipbuilders can provide approved designs.

There are several hundred “stranded” natural gas fields in the world of sufficient reserves (over 0.5 trillion cubic feet (tcf)) to support a 1.0 mtpa LNG plant for up to ten years or more. A floating LNG (FLNG) facility could also be moved to a new gas field as production declines, so extending service life to 30 to 40 years. Liquefaction of associated gas from oil production is also attractive, as it would otherwise be reinjected or flared. In all about one hundred prospects for FLNG plants of 1.0 mtpa and above have been identified (3).

Floating Production, Storage and Offloading (FPSO) is conventional for development of "stranded" oil reserves, with well over 100 FPSOs now in operation. Several vessel lease and LNG shipping companies have the capability and know-how to consider LNG FPSO projects. Engineering firms have also developed the skills to see offshore projects to completion and successful operation.

Cost and Schedule Advantages of Floating LNG

Technology developments and engineering studies have shown that cost estimates for LNG FPSOs of US$ 700 tonne per annum (tpa) can be achieved. Virtually no onshore LNG projects meet this investment cost. Offshore LNG production is commercially viable now because LNG vessel costs are relatively low compared to the major infrastructure costs needed for onshore production including gas pipeline, jetty, LNG storage tank(s), site preparation and construction facilities.

Floating LNG projects should also demonstrate shorter time to commercial production than onshore projects and can therefore provide a more flexible solution to realizing LNG offtaking and sales opportunities.

Floating LNG production has emerged from being prospective or "near future" technology to provide a competitive option to onshore LNG production and a solution to the LNG shortage.

LIQUEFACTION PROCESS EVALUATION AND SELECTION

Introduction

For many years, LNG plant licensors and engineering firms tried to apply onshore technology and plant design concepts to prospective offshore projects – with little success. Offshore processing presents quite different engineering, project management and installation challenges to an onshore plant and these issues must be addressed to determine the optimal process technology and plant design.

For offshore LNG to be commercialized, it is essential to gain the confidence of potential investors. Onshore LNG production is mature with well-established design concepts, engineering procedures and hazard mitigation practices. This experience is important for FLNG production but must be aligned with the unique requirements of an FPSO. Fundamental to ensuring the viability and acceptance of LNG FPSOs is selection of the best process technology.

Criteria for Evaluating Process Technology

Costain has undertaken conceptual design and basic engineering of offshore LNG plants for nigh on 30 years following an initial study for the UK Dept. of Energy (4). This concluded that expander-based process technology, conventional to Costain and proven on small-scale “peak-shaving” LNG facilities, had considerable merit for offshore LNG production. This conclusion counteracted “accepted wisdom” which considered offshore LNG plants would use similar liquefaction technology as large onshore plants (multicomponent hydrocarbon refrigerant or “mixed refrigerant”).

Turbo-expander refrigeration cycles work by compressing and work-expanding a suitable fluid, typically nitrogen, to generate refrigeration at high isentropic efficiency (Figure 1). The cycle gas is boosted in pressure by the brake-end of the expander. The first offshore LNG production studies included feed gas chilling by mechanical refrigeration (4) to improve overall process efficiency and thereby increase LNG production.

Expander technology was proposed for offshore LNG due to;

- Inherent safety by avoiding liquid hydrocarbon refrigerants (and their storage) and potential fire and explosion hazards
- Insensitivity to vessel motion as the refrigerant is gaseous and refrigerant distribution in the liquefaction heat exchangers is constant
- Flexibility to changes in feed gas conditions and ease of operation due to the simplicity of the process
- Rapid start-up and shutdown in a safe and controlled manner
- A small number of equipment items with consequently a relatively small plant footprint and relatively low topsides weight

The capital cost of the processing and liquefaction facilities is only a fraction of the total investment cost for the offshore facilities. Expander technology minimizes overall project cost, as well as being the safest possible design.

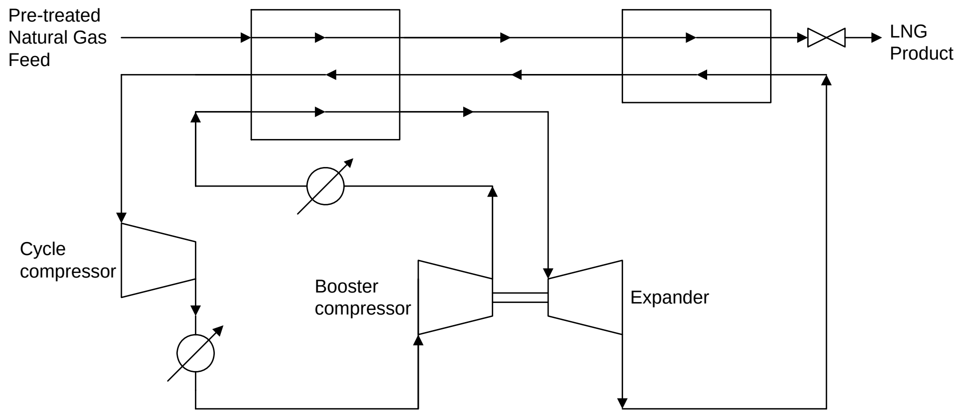

Figure 1 Turbo-expander Cycle for Gas Liquefaction

Subsequent engineering studies demonstrated three further important advantages for expander technology;

- Ease of modularization and construction due to the simplicity of the process and the low equipment count
- Use of conventional well-proven cryogenic equipment maximizes competition amongst equipment suppliers and minimizes plant cost and project schedule
- Turbo-expanders are very reliable with minimal maintenance requirements

Nitrogen Expander Process Development

In the late 1980s, Costain advocated a dual turbo-expander flowsheet based on nitrogen refrigerant (Figure 2) for the Pandora field, offshore Papua New Guinea. The process is widely used for cryogenic liquefaction of industrial gas (5). The second, colder turbo-expander improves process efficiency by reducing the temperature difference for LNG subcooling (Figure 3). Subsequently, BHP and Linde developed a dual nitrogen expander process for the proposed Bayu-Undan development (6). The European Union Azure Project (7,8) concluded this process is optimal for offshore LNG production of 1.0 to 2.0 mtpa.

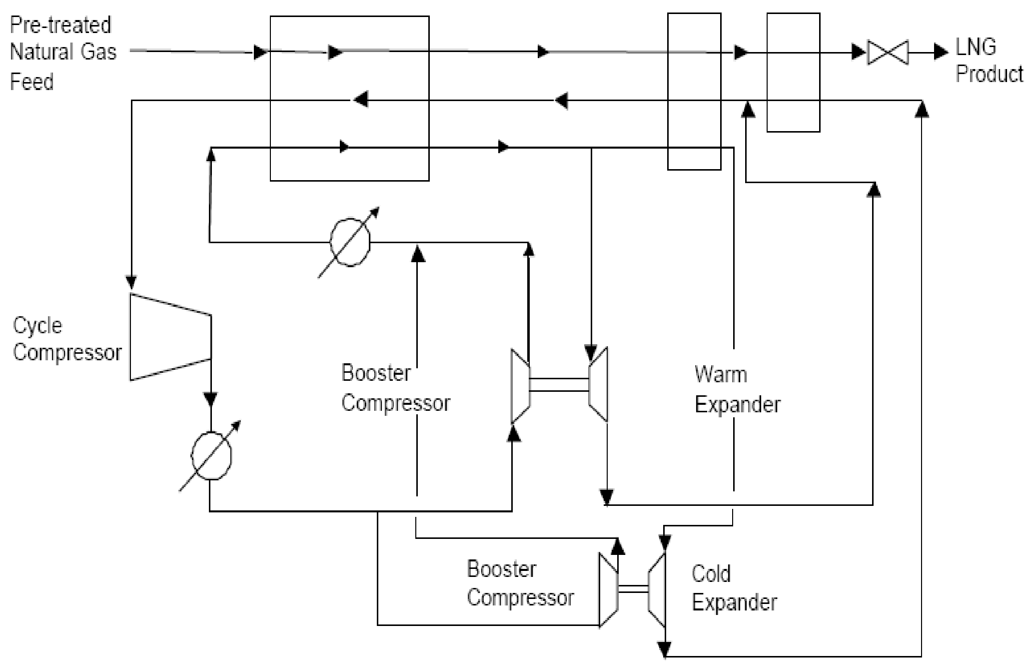

Figure 2 Dual Turbo-expander Flowsheet for Gas Liquefaction

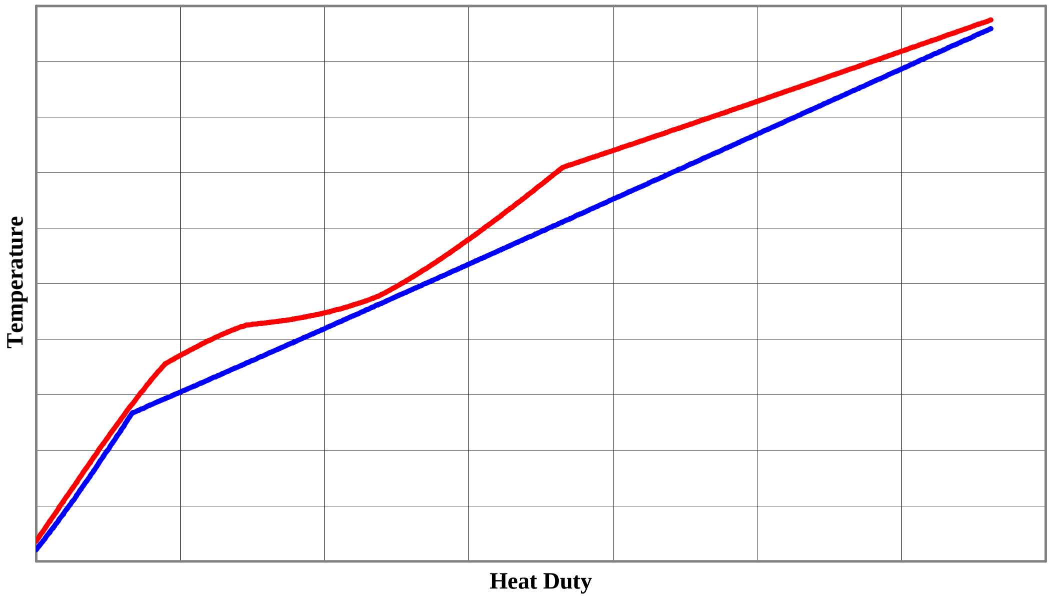

Figure 3 Typical "Cooling Curves" for Dual Turbo-expander Liquefaction

In proposing nitrogen refrigerant for the dual expander flowsheet, Costain also evaluated methane refrigerant. Methane can reduce the specific power for liquefaction by several per cent but this advantage is outweighed by the safety implications of using hydrocarbon refrigerant rather than inert nitrogen, particularly because of the increase in equipment spacing (to offset the effects of jet fires and increased blast pressures). Reducing overall plant footprint is crucial offshore and dictates many plant design and engineering decisions.

A specific power consumption of less than 0.50 kWh/kg of LNG is typical for a dual expander plant with efficient cycle compressors and turbo-expanders and optimized chilling from mechanical refrigeration. For high pressure feed gas, specific power consumption can be less than 0.40 kWh/kg, but usually the need for pressure let-down to remove ("scrub") heavier hydrocarbons and high freezing point aromatics from the feed gas means this figure is only realistic for very lean feed gas, for example where LPG is extracted upstream.

A paper presented at the 81st GPA Convention (9,10) showed that FLNG process technology and equipment was available and mostly well proven and that key marinization issues were either resolved or close to being resolved. It reiterated that the dual expander design is the best process technology for LNG capacities of 1.0 to 2.0 mtpa. Since that paper, Costain has performed further engineering studies for a range of energy majors and ship leasers.

The same reasons why nitrogen expander technology was first proposed for LNG FPSOs nearly thirty years ago still apply today. This process technology should be the first choice for a safe, robust floating LNG plant.

Alternative Refrigeration Cycles

Optimized Cascade^{SM}

In the last decade, the ConocoPhillips Optimized Cascade^{SM} liquefaction process has been employed successfully in Trinidad (four plants), Egypt (two plants) and Australia with a plant in construction in Equatorial Guinea (11). Each plant has "two trains in one" to ensure high overall availability, so each has two trains of propane, ethylene and methane refrigeration systems. Each refrigeration system has its own gas turbine driven compressor so each plant has six compressors, drivers and associated equipment. Plant designs are relatively complex, with many equipment items. An offshore plant would be very heavy and have a large footprint.

Propane and ethylene must both be stored (as liquids) for refrigerant make-up and the inventory of flammable hydrocarbons introduces significant equipment spacing distances to mitigate potential safety hazards.

This technology could only be commercially viable for very large capacities, as demonstrated by ConocoPhillips evaluations on LNG FPSOs of 5 mtpa (11,12).

Mixed Refrigerant

The vast majority of base-load LNG plants use the Air Products & Chemicals Inc. Propane Pre-cooled (C3-MR) process wherein propane is used for natural gas cooling and mixed refrigerant is used for condensing and sub-cooling. This, and other mixed refrigerant technology, including single mixed refrigerant and dual mixed refrigerant processes have been assessed for offshore liquefaction.

Mixed refrigerant plants have a significant inventory of highly flammable hydrocarbon refrigerant including storage (to make-up refrigerant losses). This needs to be made up from ethane (or ethylene), propane and butanes, either extracted from the natural gas feed or supplied from shore. This would either require extra gas processing and fractionation or methods for safe unloading and loading of volatile, flammable hydrocarbons offshore. The complexity, required deck space and mitigation of fundamental safety concerns are major hurdles to implementation of mixed refrigerant technology offshore.

Dual mixed refrigerant technology has lower hydrocarbon inventories and gives lower flaring rates in the event of refrigerant compressor trip and refrigerant blow-off. It may be the most appropriate mixed refrigerant technology available but no onshore liquefaction plant has used it yet (13).

As well as the safety concerns, liquid refrigerants rely on good distribution in the liquefaction heat exchangers, something that is difficult to achieve with a moving vessel. Mixed refrigerant plants also suffer if feed gas conditions vary and can take hours to stabilize after start-up because precise blending of the refrigerant mixture is needed.

Offshore, where start-up and shutdown could be relatively frequent, this would lead to lost production.

LNG FPSO PLANT DESIGN

Introduction

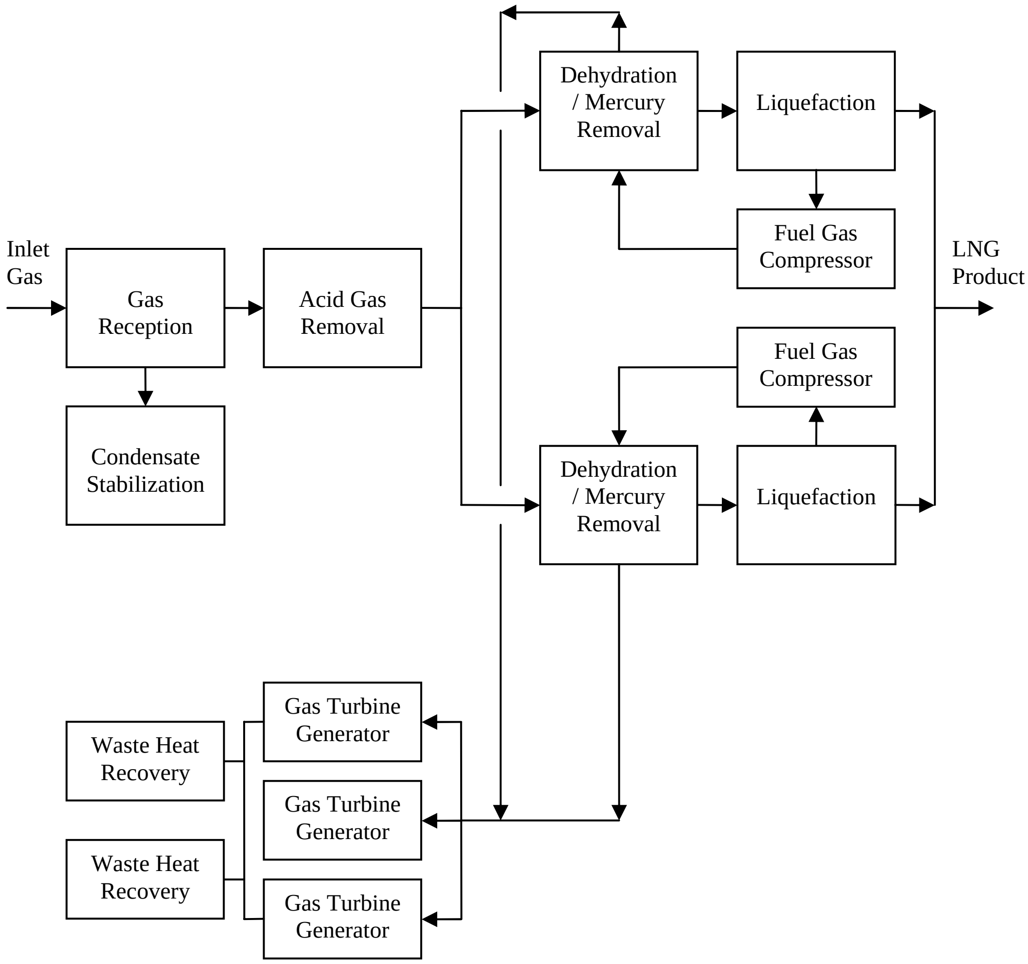

Figure 4 Simplified LNG Plant "Block Diagram" (Electrical Power Generation for Nitrogen Cycle Compressor Drives)

Offshore LNG production can use conventional process technology and equipment (Figure 4) for gas reception (including slugcatcher and filtration) and the pre-treatment section, consisting of acid gas removal, molecular sieve dehydration and mercury removal (for protection of the aluminum plate-fin heat exchangers in the liquefaction section). If the feed gas is rich in heavier hydrocarbons these may need to be removed as condensate. Aromatics, particularly benzene, must be removed to avoid freeze-up (not shown). Compared to an onshore LNG plant there is a greater incentive to minimize upstream processing so lean natural gas, of low carbon dioxide content, is preferred.

Plant Capacity

Significant reduction in LNG production costs were achieved up to about 2004 via "economies of scale" as LNG train capacities rose to 5 mtpa. However, such plant capacities are infeasible with the deck space of a conventional LNG vessel hull and less than half this capacity is more realistic. Early engineering studies (14,15) showed that a single liquefaction train using dual nitrogen expander technology could have a capacity of about 0.75 mtpa and this has been confirmed since by more detailed work. A two-train liquefaction plant of approximately 1.5 mtpa capacity can be accommodated within the available deck space of a conventional hull (~145,000 m^3 LNG).

Using two independent LNG production trains, minimal items of equipment, reliable aero-derivative gas turbines, sparing of critical equipment and formalised preventative maintenance increases the availability of the LNG plant to greater than a single train onshore plant – over 98.5% based on scheduled shutdowns. It also means equipment sizes are generally within the limits of industry experience, which ensures multiple potential suppliers and competitive costs. It also enables the plant to be laid out symmetrically to optimize topsides weight distribution and simplify module design. A single train is viable for the feed gas pre-treatment upstream of liquefaction.

A plant capacity of approximately 1.5 mtpa and this overall offshore concept has now emerged as the primary option for the majority of LNG FPSO projects being considered.

Offshore Engineering

Introduction

Engineering of an LNG FPSO brings together established methods from onshore LNG plants and oil FPSOs but includes several unique elements due to the complexity of the liquefaction system, the cryogenic equipment, the large utilities consumption (notably cooling water and possibly the electrical supply system) and the hazards of handling LNG in a relatively confined space.

Naval Architecture

Design of an LNG FPSO requires naval architects to co-ordinate LNG plant design and FPSO design practice to ensure optimal integration of the "topsides" (the processing plant and major utilities) with the hull and vessel systems (utilities, control and support). Work is ongoing with shipbuilders to optimise the design of their particular LNG storage systems and hull structures with the topsides layout to reduce overall weight and cost.

On any FPSO, space is restricted whilst process facilities must be located away from the flare, helideck and buildings, including accommodation. An integrated approach between topsides designer and vessel designer helps establish appropriate and optimal plant design and layout strategies.

Vessel Movement

An important concern with FLNG is vessel response to wave motions and the plant and equipment design requirements to mitigate motion effects. Clearly, the first plants will be located in relatively calm "benign" seas. By designing the vessel to "weathervane" to the wind, as is conventional for FPSOs, any tendency to roll will be virtually eliminated. Several specialist companies can accurately determine the effect of wave motions on vessel movement as a basis for engineering and design.

Dual expander technology is the most robust possible LNG technology with respect to vessel movement (and the easiest to restart if vessel motions become so excessive that operation must be stopped).

At Costain, we have developed our understanding of the influence of vessel movement on the effective weight of equipment and flexing of the vessel deck. Experience in designing cryogenic plants provides capability in pipework stress analysis and allowance for pipework contraction. Piping design for the liquefaction section (and including hull flexing) is one of the most important activities in generating an optimized plant layout.

Process equipment influenced by vessel movement due to wave motion should be located on the vessel centerline. All separators and columns on vapor/liquid service are potentially a concern but the most significant are the acid gas removal unit (AGRU) contactor and the amine regeneration column as maloperation can lead to carbon dioxide freezing in the liquefaction section. Satisfactory performance, to maintain the treated gas carbon dioxide level to 50 ppmv, requires multiple beds of structured packing and regular liquid redistribution to keep the downflowing liquid from tending to the column wall. Computational Fluid Dynamics (CFD) is valuable in confirming the column internals design and avoiding excessive design margins on column height.

If during operation the treated gas carbon dioxide content was excessive, the molecular sieve dehydration system could be overloaded if this had not been considered in design. The sensitivity of the dehydration system has been evaluated for high carbon dioxide to ensure a robust and optimal design.

Engineering Specifications and Classification

Engineering specifications and standards used for onshore LNG plants apply to topsides design but all offshore facilities must be approved by a classification society such as Lloyds Register, Det Norske Veritas (DNV) and American Bureau of Shipping (ABS). Amongst the activities and responsibilities of the classification society are;

- Combine best practice from oil and gas carriers
- Use existing standards as far as feasible
- Add specific LNG and leakage considerations
- Formally qualify novel technology
- Use risk assessment for novel hazards

The classification society has a key role in producing the Coarse Safety Assessment at an early stage of engineering to identify hazards and risk mitigation measures and procedures. At this juncture the plant design, plant layout, environmental and safety studies should be detailed enough to proceed to permitting. The classification society would act as a formal design authority and produce the Formal Safety Assessment for detailed engineering.

A key focus of recent engineering and technical development at Costain has been how classification society requirements differ from conventional engineering standards for LNG plants and to work with the classification societies to ensure that proposed equipment and plant is compliant. Classification society verification, auditing and approval of design methods and materials has needed close co-operation between suppliers, classification society and engineering team.

Plant Standardization

Engineering of a floating liquefaction plant is a quite different logistical and scheduling challenge to an onshore plant. An offshore LNG plant is designed as modules for ease of installation and for minimal “hook-up” of pipework, instrumentation and services to minimize the schedule to first LNG. Strict fabrication and construction timescales must be met in a shipyard or construction of several ships can be delayed. The whole process concept, flowsheet, plant design and all aspects of engineering must be aligned with minimising weight, ensuring good weight distribution and supporting the overall modularization strategy.

Offshore LNG requires a “construction-led” approach to engineering using standard “systems” and module designs. In our earlier work (9,10) a feed gas composition suitable for a large majority of prospective projects (particularly offshore Australia and West Africa) was used as a basis of design. The standard plant design included for a carbon dioxide level in the feed gas of up to 4 mol.% and upstream condensate removal, with space allocated on deck for further equipment to remove greater levels of feed gas carbon dioxide, increase feed gas pressure to over 40 bars if necessary and handle sulfur compounds. For specific feed gas conditions the performance and LNG production capacity of the standard plant is calculated by process simulation. If appropriate, equipment changes or additions can be made for specific feed gas conditions but as far as possible, the LNG plant design should be standardized.

The standard plant approach minimizes engineering time, reduces changes to equipment and topsides design and enables the overall delivery schedule to be reduced by many months compared to a customized plant design. This overall approach is also consistent with relocating a production facility with minimal equipment changes at some point in the future.

LIQUEFACTION SYSTEM

Power Generation and Cycle Compressor Configuration

Choice of Compressor Driver

A two-train liquefaction plant of 1.5 mtpa capacity requires up to 90 MW for nitrogen cycle compression. Onshore LNG plants use refrigerant compressors driven by industrial heavy-duty gas turbines but these are not practicable offshore. Aero-derivative gas turbines have been proposed for offshore LNG from the earliest evaluations (4) as they have a number of important advantages over their industrial counterparts;

- Smaller footprint and much lower weight – around half that of an industrial unit of comparable power output. These factors are especially important offshore
- High availability and reliability (with a lower duration for planned maintenance and less than 0.5% unscheduled downtime). Engine sections are modular and light and can be replaced in less than 24 hours without specialist technical support
- Higher thermal efficiency – over 40% compared to 30% for an industrial unit so saving on fuel and reducing carbon emissions

However, aero-derivative gas turbines have not often been used, even onshore, as large process compressor drives raising concerns over reliable start-up and operation and whether they could offer similar (high) availability to the Frame 5 and Frame 6 industrial heavy-duty gas turbines used on most onshore LNG plants.

Concerns with direct drive of cycle compressors led to most studies being based on electrical power generation by gas turbines and motor driven cycle compressors. However, electric motors of 40 to 45 MW are outside the experience of both the LNG business and most suppliers. Therefore, neither direct drive nor motor drive can be considered “conventional”.

Choice of motor drive or direct drive depends on a number of factors;

- Availability
- Equipment size and weight
- Efficiency
- Operational experience

Availability

Using aero-derivative gas turbines as direct compressor drives means that a gas turbine trip would require shutdown of an LNG train. A power generation system could continue in the event of a single gas turbine trip, as an additional spare gas turbine would be included (N+1 principle where N is the number of items needed for operation). What this means to overall plant availability has required detailed assessment but in summary, the high reliability of aero-derivative gas turbines means the justification for motor drives is not as high as anticipated by earlier studies, particularly as the electrical system is relatively complex.

Equipment Size and Weight

Electrical power generation requires considerable equipment and space, especially if variable frequency drive were needed for efficient capacity control of LNG production. From the perspectives of equipment size, weight, structural steel and associated capital cost, aero-derivative gas turbines as direct compressor drives have an advantage over large-scale power generation and motor drives.

Efficiency

Overall fuel gas consumption is higher for the electric motor drive option as up to about 8% of shaft power is lost through the electrical generator, transformer, harmonic filter and motor.

Operational Experience

Onshore LNG plant licensors, engineering firms and operators have reappraised the use of aero-derivative gas turbines in recent years, primarily due to their high thermal efficiency and low emissions and as they became more popular for electrical generation. The ConocoPhillips/Bechtel designed plant (11) at Darwin, Australia uses GE LM2500+ aero-derivative gas turbines as refrigerant compressor drivers and has been in successful operation since 2006.

The GE LM6000 exhibits high thermal efficiency and reliability, and is an established power generation package with over 650 units in operation. Unlike the LM2500+ (and Rolls-Royce RB211, which has a similar power output) it is not a true “dual shaft” gas turbine. Costain has closely evaluated this in developing plant start-up and control strategies.

Aero-derivative Gas Turbine	Power Output @ ISO Conditions MW
Rolls Royce RB211 GT61	33
GE LM2500+ G4	34
GE LM6000 PD	43
Rolls Royce “Trent”	52

Table 1 Power Outputs of Available Aero-derivative Gas Turbines

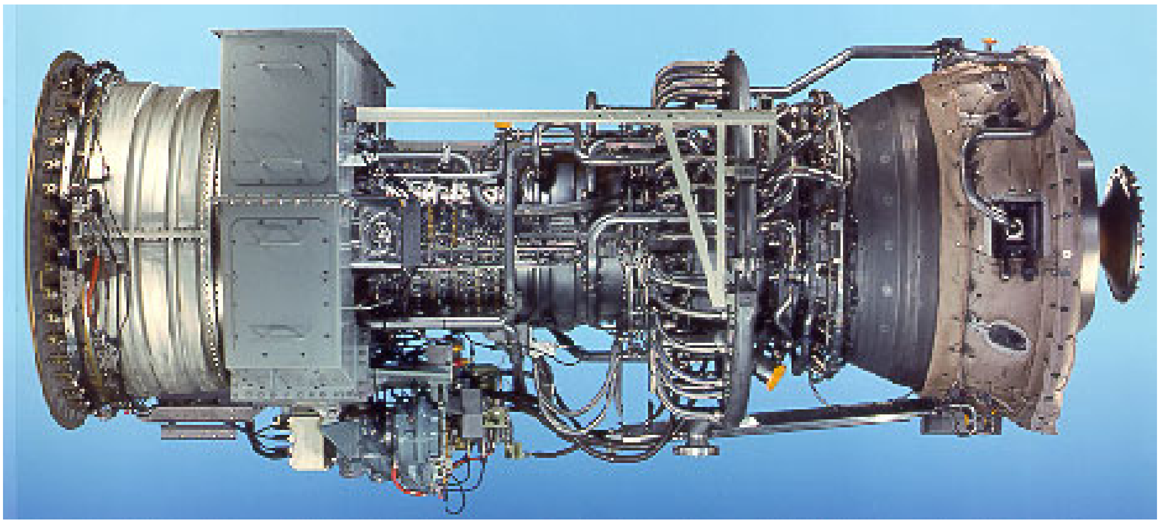

Figure 5 LM6000 Power Generation Package

Centrifugal compressors of about 40 MW are within the capability of the major compressor suppliers. A number of motor suppliers offer designs or are close to developing them for this duty based on synchronous machines with wide speed range and high efficiency. Motor driven compressors may be more responsive and afford better process control than a gas turbine driver but this may not be significant if the LNG plant operates at a relatively constant feed gas flow.

The LM2500+ and RB211 are candidates for compressor drivers on an LNG FPSO. They have lower power output than the LM6000, with four units being similar in power output to three LM6000 units. However, if comparing the LM2500+ or RB211 as a direct drive with the LM6000 as an electrical generator, both options would require four units (N+1 on power generation) and the LM2500+ and RB211 could be very competitive.

The development of the LM6000 as a direct drive may be the most promising option to reduce the number of machines and has received significant effort (16). The Rolls-Royce "Trent" was proposed for LNG FPSOs ten years ago (6,15). It has since been employed as a mechanical drive on pipeline compressors and is under development as a marine compressor drive.

Effective packaging of the compressor/gas turbine driver set is very important and has been a key aspect of Costain's supplier selection activities.

Turbo-Expanders

The application of turbo-expanders with nitrogen at the required process conditions, pressure ratio and capacities is conventional. As frame sizes are at the higher end of the manufacturer's range, efficiencies are high – expander isentropic efficiencies approach

90% whilst compressor (brake-end) polytropic efficiencies approaching 85% can be expected (17).

Active magnetic bearings (AMB) on radial inflow turbo-expanders were introduced in the early 1990s and are now conventional technology. Compared to oil lubricated machines they reduce footprint and weight, simplify operation and ensure the nitrogen cannot be contaminated with lube oil.

Process simulations, assessments and sensitivity studies have identified how to optimize nitrogen cycle pressures for a range of feed gas conditions to ensure high expander and compressor efficiency.

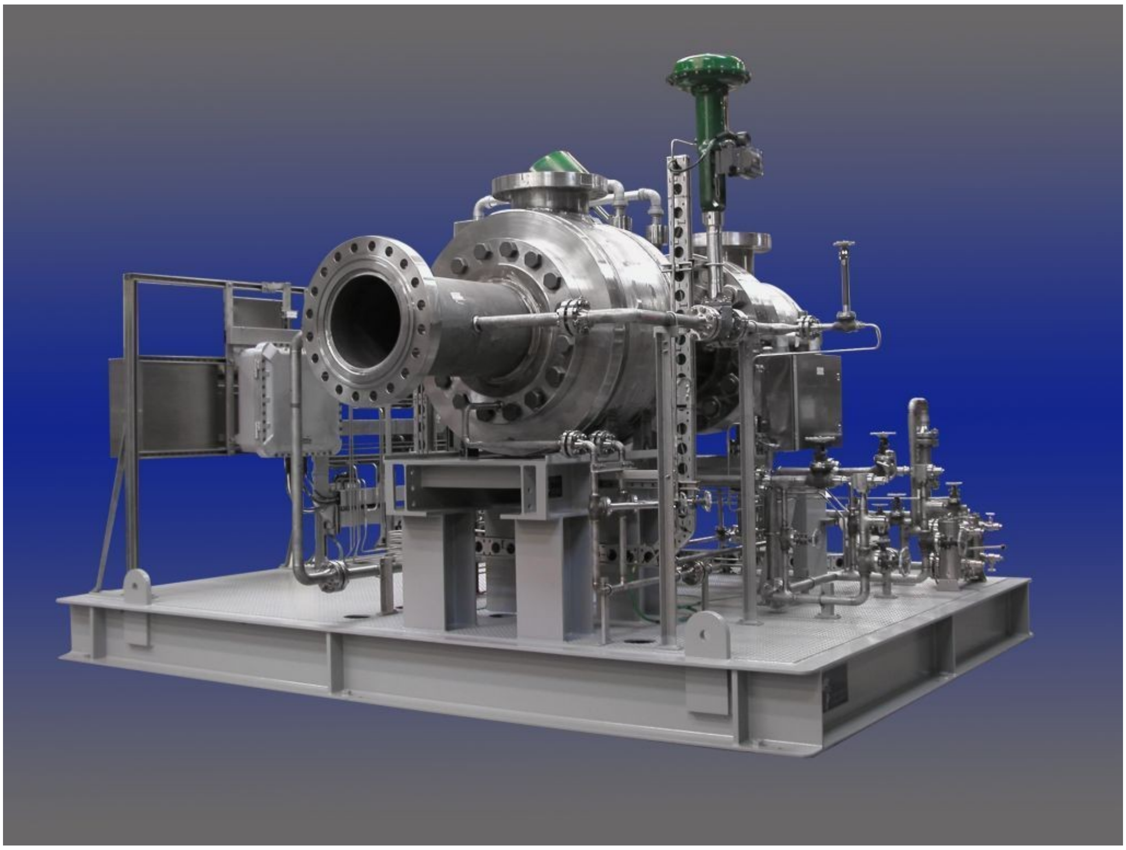

Figure 6 Turbo-expander with Active Magnetic Bearings (courtesy of Mafi-Trench Company)

Mechanical Refrigeration

As discussed, a benefit of the dual nitrogen expander cycle is that no refrigeration system or refrigerant storage is necessary. However, chilling the inlet air to the gas turbine can increase power generation by as much as 30% and is normal practice in hot, tropical climates. As LNG production capacity is based on utilising available power, this increase can lead to a similar increase in LNG production if liquefaction equipment is suitably sized. This factor led Costain to utilize inlet air cooling on a proposed offshore LNG facility (Tassie Shoal) as long ago as 2002.

Clearly, the extra cost, weight and footprint of a refrigeration system, refrigerant storage system and inlet air chillers must be justified by the additional production capacity of the LNG plant. However, the chilling system can also be employed on the feed gas and on the cooling water (6,9,10) to reduce the temperature of the high pressure nitrogen downstream of the cycle compressor coolers. Feed gas chilling improves process efficiency and can reduce molecular sieve dehydration duty significantly. Chilling the plant cooling water can increase LNG production by several percent.

The selected refrigerant should be non-flammable (so excluding propane) and have both limited “ozone depletion potential” and limited “greenhouse potential”.

Liquefaction Heat Exchangers and Cold Boxes

Aluminum plate-fin heat exchangers, conventional in cryogenic natural gas processing onshore are ideal for floating liquefaction by virtue of being light, compact and highly efficient for multistream duties. Extensive experience with high-pressure exchangers on hydrocarbon service has enabled Costain to optimize exchanger design and heat transfer fin selection (in terms of Chilton-Colburn j factor and Fanning f factor (18)) in parallel with optimizing nitrogen cycle operating pressures and performance (using AspenTech’s MUSE/MULE/MUSC suite of programs) so as to maximize LNG production against cold box footprint and weight.

The plate-fin heat exchangers are located in a cold box and completely insulated and weatherproofed. Cold box designs can accommodate several exchanger blocks (“cores”) so one cold box is suitable for approximately 0.75 mtpa of LNG production. The internal piping arrangement is simple and there are no unusual mechanical design or exchanger support issues. Large bore pipework outside the cold box presents some technical challenges in resolving transitions from aluminum to stainless steel and in ensuring suitability for the forces imposed by vessel movement.

UTILITY SYSTEMS

Process Cooling

Air-cooling would require a prohibitive amount of deck space and cannot be justified.

Seawater cooling is conventional in offshore hydrocarbon processing but the cooling duty on an LNG FPSO is much greater than for oil processing and associated gas compression. A 1.5 mtpa LNG FPSO requires about 15,000 cubic metres per hour of cooling water based on a 10 C rise in water temperature (including for pre-treatment). The cooling system has an important influence on the required deck space.

The cooling system can be either an open loop or closed loop system. In the open loop system, seawater is drawn in, filtered, treated to avoid fouling and pumped through the nitrogen cycle compressor intercoolers and aftercoolers before discharge back to sea. All heat exchangers and pipework must use non-corrosive materials, typically titanium. In the closed loop system, process grade cooling water is pumped around a closed loop, with heat of compression being removed and then rejected to seawater in cooling water/seawater heat exchangers. Exchangers and pipework on process grade cooling water service can be carbon steel.

The open loop system operates at seawater temperature whereas the closed loop system must operate at a higher temperature to provide a reasonable temperature driving force between the cooling water and the seawater used to cool it. Based on a 10 C temperature difference, the closed loop system reduces process efficiency by about 6%, with an equivalent reduction in LNG production. Hence most studies used open loop cooling, even though the need for expensive metallurgy represented a large investment.

More detailed engineering studies have questioned the use of open loop cooling. Compact heat exchangers can provide efficient nitrogen cycle cooling at very small temperature driving forces and occupy a fraction of the space of a conventional shell and tube exchanger at a fraction of the weight. The reduction in topsides weight can more than compensate for the higher process efficiency of the open loop system.

As noted earlier, mechanical refrigeration introduces a chilled water circuit with the refrigeration system being cooled by the main cooling water system.

Process Heating

Process heating is needed for the molecular sieve pretreatment system, acid gas removal system and condensate stabilization. The amount of waste heat available from the gas turbines exceeds process requirements so most evaluations have concluded this is the most cost-effective and thermally efficient solution for process heating. Hot oil is normally preferred to steam based on higher thermal efficiency, less equipment items and ease of operation though steam could potentially drive a turbine for power generation and increase overall thermal efficiency by using a greater amount of the available waste heat.

If high pressure steam or condensate could be made available from the vessel this could be advantageous and is a consideration for optimized LNG FPSO designs.

PLANT DESIGN, ENVIRONMENT AND SAFETY

Operation of the Liquefaction System

As the nitrogen refrigerant has a constant composition and the refrigeration system is simple, it is relatively easy to assess how to change refrigeration cycle parameters to optimize performance and maximize LNG production. Experience from operation of smaller-scale cryogenic liquefiers and LNG plants is very relevant.

Environmental Emissions and Mitigation

The environmental impact of offshore LNG production is less than onshore production simply because there are no onshore construction activities so environmental impact assessments are not the potential bottleneck they can be onshore.

Assessment of treatment options should use a “Best Available Technique” approach to ensure minimal delay to permitting being sanctioned. The major emissions are;

Carbon Dioxide

The acid gas removal unit produces a carbon dioxide effluent with minor amounts of hydrocarbons, which is vented to atmosphere at a safe height. Dispersion studies can determine the minimum height for safe venting.

Gas Turbine Exhaust

The turbine exhaust gas is predominantly nitrogen, carbon dioxide and water with small amounts of carbon monoxide and trace levels of nitrogen oxides and sulfur oxides. The high thermal efficiency of aero-derivative gas turbines compared to industrial heavy-duty gas turbines means that although liquefaction process efficiency is lower than most onshore LNG plants, fuel consumption and total exhaust emissions are similar.

Dry Low Emissions (DLE) technology is well developed on aero-derivative gas turbines. Nitrogen oxide emissions below 25 ppm are achievable today and it is likely that lower figures will be achieved in the future.

Flaring

There is zero hydrocarbon flaring under normal operating conditions, other than a nominal purge flow.

A high integrity pressure protection system (HIPPs) can be employed at the plant inlet as with all gas plants that utilize a feed gas let-down valve. This avoids a “full flow relief case” and has a direct effect on reducing flare load, the impact due to flaring and flare tower height.

Plant Layout

Safety considerations are paramount to plant layout. Layout criteria for an FPSO are more stringent than onshore due to the limited footprint (only 8,000 to 10,000 m^2 typically), the need for good weight distribution and the need for personnel refuge and escape routes.

Hazard mitigation and blast overpressure are critical elements for layout and the benefits of nitrogen refrigerant become apparent in setting safety distances and minimum spacing for equipment.

Design reviews must focus on minimizing piping runs of large bore pipework including cooling water and cryogenic nitrogen cycle pipework, which is heavily insulated. The effect of pipework weight on the extent and weight of structural steel can be significant. Minimizing pipework weight by layout optimization has been essential in minimizing topsides weight and confirming the overall feasibility of the 1.5 mtpa LNG FPSO.

Safety

Onshore LNG production plants have enjoyed an excellent safety record. Offshore LNG introduces more stringent requirements due to the congested nature of the plant, storage and personnel areas and it is essential that experience from design and operation of onshore LNG plants is utilized.

The primary safety concern is the inventory of hazardous, flammable gas and LNG and the consequence of any loss of containment. Major Accident Hazard Reviews are essential to;

- Ensure the integrity of all methods of primary containment
- Inhibit the potential formation of flammable vapor which could cause fire or explosion
- Identify mitigation measures

Using nitrogen refrigerant greatly minimizes the hydrocarbon inventory and the simplicity of the plant design can ensure the layout is relatively uncongested, with acceptable blast overpressures. Quantitative Risk Assessment (QRA) shows lower risk than many onshore LNG plants. Of course, location of the accommodation, control building, helideck, flare and safety refuge areas are critical to personnel risk and firewalls are necessary to meet segregation requirements.

The usual Safety, Health and Environmental (SHE) requirements for an onshore LNG plant are applicable and integral to the QRA. Safety philosophies are needed for prevention of incidents (e.g. avoidance of LNG leakage and ignition) and hazard mitigation including active and passive fire detection, gas detection and emergency shutdown (ESD). Safety studies and technical assessments should include determination of fire areas, gas dispersion modeling and personnel escape/evacuation, design accidental loads (DAL) for all aspects of the facility and the effect of LNG on vessel structural steel.

Risk based assessments must show that risks are “as low as reasonably practicable” (ALARP). Conventional engineering and safety assessments, including Hazard Identification (HAZID) and Hazard and Operability (HAZOP) studies, focus on “safety by design”.

The simplicity of the dual nitrogen turbo-expander plant lends itself to FPSO custom and practice but the plant operations team should be experienced LNG plant operators.

Classification society requirements have addressed statutory and regulatory issues for fundamental plant safety (6,7,9,10,12). The classification societies have developed requirements for LNG FPSOs from existing rules and guidelines for LNG carriers and have completed Coarse Safety Assessments of LNG FPSOs. For detailed engineering, a classification society will act as “design authority” and is responsible for the Formal Safety Assessment, developed with the engineering team, that determines the fundamental safety criteria, philosophies and procedures.

Work to date is clear that there are no obstacles to the safe design of a floating LNG plant using nitrogen refrigerant.

Modularization

A significant advantage of turbo-expander technology for offshore LNG is that the plant can be designed as modules more easily than with other liquefaction technologies. It can therefore be built away from the shipyard, which provides opportunities for capital cost saving and high quality fabrication with established module suppliers.

Module limits are based on what can be fabricated (either local to the shipyard or local to a port for transporting to the shipyard). A nominal limit of 2000 tonnes is pragmatic to ensure crane availability. Cold boxes and rotating equipment packages are provided to the module fabricator fully piped, wired and tested and this philosophy is extended through all major equipment as far as practicable to simplify, installation and hook-up of utilities, instrumentation and other services.

As fabrication of the vessel and the topside modules can be performed in parallel, the time to vessel delivery and full LNG production can be reduced by many months compared with a similar capacity plant onshore.

CONCLUSION

Offshore LNG production now provides a competitive alternative to onshore LNG at a time of LNG shortage. With uncertain gas prices and project funding for major projects becoming more difficult, the commercial case for floating LNG becomes even better due to the smaller capacity of floating LNG projects, the lower cost and the reduced time to first production.

Evaluation of the major criteria that influence commercial acceptance of floating LNG production – safety, overall cost, performance, availability and delivery schedule – led to selection of the dual nitrogen expander liquefaction process. This well proven process has now been evaluated in detail for offshore conditions and plant capacities in terms of technical risk, equipment design and availability, topsides design, ease of modularization, plant performance and operation, delivery schedule, safety and environmental impact. These engineering studies have further reiterated that this liquefaction technology is the outstanding candidate for offshore LNG projects.

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