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ARE FLOATING LNG FACILITIES VIABLE OPTIONS?

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Are floating LNG facilities viable options?

Here's how to evaluate technological and commercial issues of these units

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Technology developments in offshore liquefied natural gas (LNG) storage and transfer have made offshore LNG production commercially viable, even at plant capacities of 1 million tpy (Mtpy) to 2 Mtpy. Due to rising costs for onshore LNG facilities, floating LNG (FLNG) is cost competitive.

Floating plants will use liquefaction processes based on turboexpanders to generate the refrigeration. This technology has been used onshore for small-scale LNG production and offers important advantages including:

- Inherent process safety
- Simple design
- Ease of operation
- Smaller footprint
- Low topsides weight.

The overall project cost and schedule to first LNG production can be competitive with base-load onshore production.

FLNG 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 refrigerant compression system configurations and the associated compressor drivers is particularly a key area. The need for marinization and topsides interfacing with the hull are also novel aspects of liquefaction plant design. Techno-commercial issues associated with floating LNG and how they are resolved will be discussed.

Shortages from conventional sources. Increasing demand for LNG has led to the upgrading of existing import terminals and new regasification facilities in the US, Western Europe, India and China. In parallel, deliveries of new LNG carriers are at record high levels. Several new LNG plants will start up in 2009, but many proposed LNG production capacities will not materialize, creating a shortfall in worldwide LNG production of up to 150 Mtpy 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 on projects have been postponed because of escalating plant costs (due to shortages in raw materials and limited human resources in engineering and construction firms). It is unlikely that the many delayed or postponed LNG projects will be implemented soon.[1]

Floating LNG potential. The difficulties with onshore LNG projects have renewed interest in offshore LNG production. Studies over the last 30 years have 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 where several suppliers have commercial systems available. 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). Today, several LNG storage systems are certified and LNG shipbuilders can provide approved designs.

There are several hundred "stranded" natural gas fields in the world of sufficient reserves (over 0.5 tcf) to support a 1.0 Mtpy LNG plant for up to 10 years or more. FLNG facilities can be moved to a new gas field if production declines, which may extend the service life 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 100 prospects for FLNG plants producing < 1.0 Mtpy 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. Technology developments and engineering studies have shown that cost estimates for LNG FPSOs at $700 tpy 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 tanks, site preparation and construction facilities.

FLNG projects usually demonstrate shorter time to commercial production compared to onshore projects, providing 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 future LNG shortages.

Liquefaction process evaluation and selection. For many years, LNG plant licensors and engineering firms tried applying onshore technology and plant design concepts to prospective offshore projects—with little success. Offshore processing presents different engineering, project management and installation challenges compared to an onshore plant. 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 selecting the best process technology.

Criteria for evaluating process technology. A study completed for the United Kingdom Department of Energy indicated that expander-based process technology, proven on small-scale "peak-shaving" LNG facilities, had considerable merit for offshore LNG production.[4] This conclusion counteracted "accepted wisdom" that considered offshore LNG plants should use similar liquefaction technology as large onshore plants (multi-component 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 (Fig. 1). The cycle gas is boosted in pressure by the expander's brake-end. The first offshore LNG production studies included feed gas chilling by mechanical refrigeration to improve overall process efficiency, thus, increased LNG production.[4]

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 process simplicity
- Rapid startup 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 offshore facilities. Expander technology minimizes overall project cost, and represents the safest possible design.

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

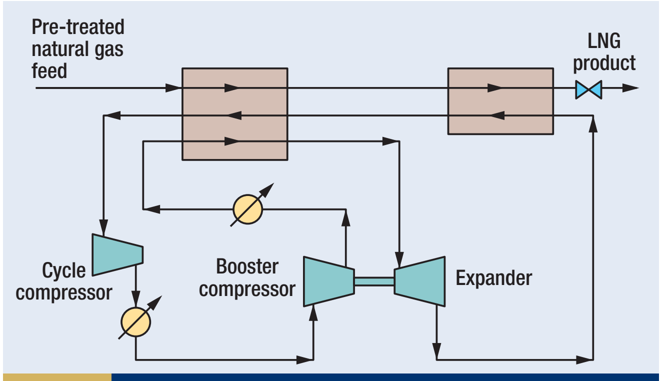

FIG. 1 Turbo-expander cycle for gas liquefaction.

- Ease of modularization and construction due to process simplicity and low equipment count
- Use of conventional well-proven cryogenic equipment maximizes competition among 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, a dual turbo-expander flowsheet based on nitrogen refrigerant, was advocated for the Pandora field, offshore Papua New Guinea (see Fig. 2). 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 (Fig. 3). Subsequently, a dual nitrogen expander process was developed for the proposed Bayu-Undan development.[6] The European Union Azure Project concluded that this process is optimal for offshore LNG production of 1 Mtpy to 2 Mtpy.[7,8]

In proposing nitrogen refrigerant for the dual-expander flowsheet, methane refrigerant was also evaluated. Methane can reduce the specific power for liquefaction by several percent but this advantage is outweighed by the safety implications of using hydrocarbon refrigerant rather than inert nitrogen. This is due to an increase in equipment spacing, which decreases the

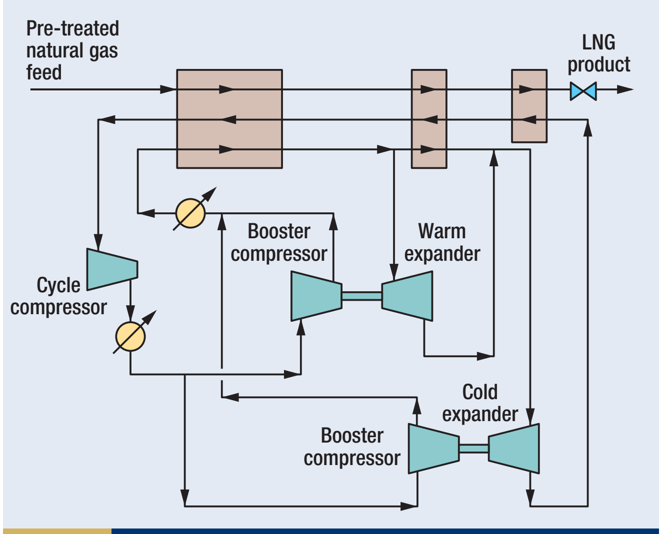

FIG. 2 Dual turbo-expander flowsheet for gas liquefaction.

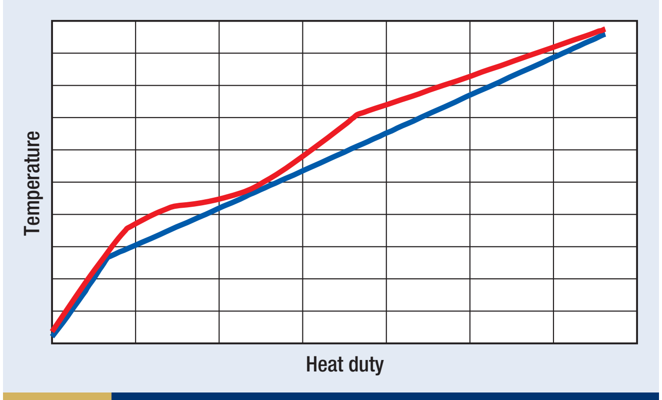

FIG. 3 Typical cooling curves for dual turbo-expander liquefaction.

propensity of jet fires and blast pressures. Reducing the overall plant footprint is crucial offshore and dictates 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 with optimized chilling from mechanical refrigeration.[9,10] For high-pressure feed gas, specific power consumption can be less than 0.40 kWh/kg. Usually, the need for pressure let-down to remove ("scrub") heavier hydrocarbons and high freezing point aromatics from the feed gas indicates this figure is only realistic for very lean feed gas (e.g., liquefied petroleum gas (LPG) is extracted upstream).

Mixed refrigerant. The vast majority of base-load LNG plants use a process wherein propane is used for natural gas cooling and a 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). The refrigerant should be ethane (or ethylene), propane and butane, extracted from natural gas feed or supplied from shore. This requires extra gas processing and fractionation or methods for safe unloading and loading of volatile, flammable hydrocarbons offshore. The complexity increases deck space and mitigation of fundamental safety concerns, which are major hurdles for 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 implemented this technology yet.[11]

As well as safety concerns, liquid refrigerants rely on good distribution in the liquefaction heat exchangers, which 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 startup because precise blending of the refrigerant mixture is needed. Offshore, where startups and shutdowns may be relatively frequent, this may lead to loss in production.

LNG FPSO plant design. Offshore LNG production can use conventional process technology and equipment, see Fig. 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, they may need to be removed as condensate. Aromatics, particularly benzene, must be removed to avoid freeze-up. Compared to an onshore LNG plant, there is greater incentive to minimize upstream processing so lean natural gas, with low CO_2 content is preferred.

Plant capacity. Significant reduction in LNG production costs is achieved with large LNG train capacities, typically up to 5 Mtpy. 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 indicated that a single liquefaction train using dual nitrogen expander technology could have a capacity of about 0.75 Mtpy.[12,13] A two-train liquefaction plant of approximately 1.5 Mtpy capacity can be accommodated within the available deck space of a conventional hull (~145,000 m^3 LNG).

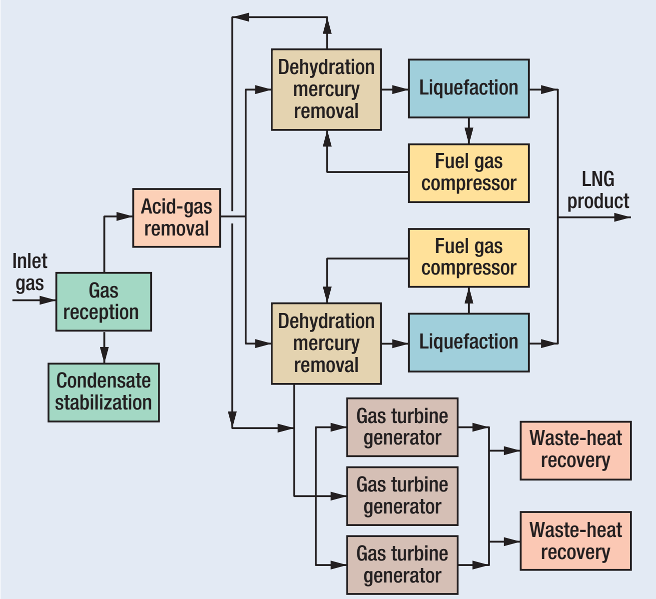

FIG. 4 Simplified LNG plant diagram (electrical power generation for nitrogen cycle compressor drives).

Using two independent LNG production trains, minimal equipment, reliable aero-derivative gas turbines, sparing of critical equipment and formalized preventive maintenance will increase the availability of the LNG plants to produce more than a single train onshore plant—over 98.5% based on scheduled shutdowns. So, equipment sizes are generally within the limits of industry experience, ensuring multiple potential suppliers and competitive costs. It also enables the plant to be laid out symmetrically to optimize topsides weight distribution and to simplify module design. A single train is viable for the feed gas pre-treatment upstream of liquefaction. A plant capacity of approximately 1.5 Mtpy with this overall offshore concept, has now emerged as the primary option for the majority of LNG FPSO projects being considered.

OFFSHORE ENGINEERING

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

Design. Design of an LNG FPSO requires naval architects to coordinate 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 optimize 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 since process facilities must be located away from the flare, helideck and buildings. An integrated approach between topsides designer and vessel designer helps establish appropriate and optimal plant design and layout strategies.

An important concern with an 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). There needs to be an understanding how the vessel movement influences the effective equipment weight and vessel deck flexing. 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 an important activity in generating an optimized plant layout.

Equipment. 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. The most significant are the acid gas removal unit (AGRU) contactor and the amine regeneration column as maloperation can lead to CO_2 freezing in the liquefaction section. Satisfactory performance, to maintain the treated gas CO_2 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 are valuable in confirming the column internals design and avoiding excessive design margins on the column height.

If, during operation, the treated gas CO_2 content is excessive, the molecular sieve dehydration system may be overloaded if this was not considered in the design. The sensitivity dehydration system sensitivity should be evaluated for high CO_2 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 and the American Bureau of Shipping. Amongst the classification society activities and responsibilities 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 and environmental and safety studies should be detailed enough to proceed to permitting. The classification society acts as a formal design authority and produces the formal safety assessment for detailed engineering.

A key focus of recent engineering and technical development is how the classification society requirements differ from conventional engineering standards for LNG plants and ensures that the proposed equipment and plant are compliant. Classification society verification, auditing and approval of design methods and materials needs close cooperation between suppliers, classification society and the engineering team.

Plant standardization. Engineering of a floating liquefaction plant is a quite a different logistical and scheduling challenge compared to an onshore plant. An offshore LNG plant is designed as modules for installation ease 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 the construction of several ships may be delayed. The whole process concept, flowsheet, plant design and all aspects of engineering must be aligned with minimizing 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 previous work, a feed-gas composition suitable for a large majority of prospective projects (particularly offshore Australia and West Africa) was used as a design basis.[9,10] Standard plant design handles CO_2 levels in the feed-gas up to 4 mol%. The design has an upstream condensate removal system with space allocated on deck for further equipment to remove greater levels of feed-gas CO_2 and sulfur compounds. If necessary, the feed-gas pressure can be increased to over 40 bars. For specific feed-gas conditions, the performance and LNG production capacity of a standard plant is calculated by process simulation. Equipment changes or additions can be made for specific feed-gas conditions, but the LNG plant design should be standardized as much as possible.

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 in the future.

LIQUEFACTION SYSTEM

A two-train liquefaction plant of 1.5 Mtpy 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. These have long been proposed for offshore LNG and have a number of important advantages over their industrial counterparts that include:[4]

- Smaller footprint and much lower weight—around half of an industrial unit with 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 saving on fuel and reducing carbon emissions.

However, aero-derivative gas turbines have not been used often, even onshore. Large process compressor drivers raise concerns over reliable start up and operation, and offer similar 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 (Fig. 5) and motor-driven cycle compressors. However, electric motors of 40 MW 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 several factors, including:

- Availability

- Equipment size and weight
- Efficiency
- Operational experience.

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). So, overall plant availability requires detailed assessment. In summary, the high reliability of aero-derivative gas turbines indicates that the justification for motor drives is not highly as anticipated by earlier studies, particularly since the electrical system is relatively complex.

Electrical power generation. This requires considerable equipment and space, especially if variable-frequency drives 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. 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.

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. Recent evaluations have considered efficient plant start-up and control.

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 a 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 an LNG plant operates at a relatively constant feed-gas flow.

Turbo-expanders. The application of turbo-expanders with nitrogen at required process conditions, pressure ratio and capacities is conventional. Since frame sizes are at the higher end of the manufacturer's range, efficiency is high. Expander isentropic efficiencies approach 90% while compressor (brake-end) polytropic efficiencies approaching 85% can be expected.[14]

Active magnetic bearings on radial inflow turbo-expanders were introduced in the early 1990s and are now a conventional technology (Fig. 6). Compared to oil-lubricated machines, they reduce footprint and weight, simplify operation and ensure that 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.

Mechanical refrigeration. As previously 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%. As LNG production capacity is based on utilizing available power, this increase can lead to a similar increase in LNG production if liquefaction equipment is suitably sized.

Clearly, the extra cost, weight and footprint of a refrigeration system, refrigerant storage system and inlet air chillers must be justified by the additional LNG production capacity. However, the chilling system can also be employed on feed gas and cooling water to reduce the temperature of the high-pressure nitrogen downstream of the cycle compressor coolers.[6,9,10] 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 (excluding propane) and have both limited ozone depletion and greenhouse potential.

FIG. 5 Power generation package.

FIG. 6 Turbo-expander with AMB (courtesy of Mafi-Trench Co.).

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 some companies to optimize exchanger design and heat transfer fin selection (in terms of the Chilton-Colburn j factor and the Fanning f factor) in parallel with optimizing nitrogen cycle operating pressures and performance to maximize LNG production against cold-box footprint and weight.[15]

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 Mtpy 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. 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 compared to oil processing and associated gas compression. A 1.5 Mtpy LNG FPSO requires about 15,000 cubic m^3/h of cooling water based on a 10°C rise in water temperature (including pre-treatment). The cooling system has an important influence on the required deck space.

The cooling system can be either an open-loop or a 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 discharged 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. Most studies, therefore, 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 previously mentioned, 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 and acid-gas removal systems, and condensate stabilization. The amount of waste heat available from the gas turbines exceeds process requirements, so most evaluations have concluded that this is the most cost-effective and thermally efficient solution for process heating. Hot oil is normally preferred to steam-based for higher thermal efficiency, fewer equipment items and ease of operation. 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 is available from the vessel this could be advantageous and is a consideration for optimized LNG FPSO designs.

Plant design, environment and safety. Since 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.

The environmental impact of offshore LNG production is less than onshore production simply because there are no onshore construction activities. 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:

- **CO_2.** The AGRU produces a CO_2 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, CO_2 and water with small amounts of CO and trace levels of NO_x and SO_x. 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 technology is well developed on aero-derivative gas turbines. NO_x 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 m^2 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 that 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 Mtpy LNG FPSO.

SAFETY

Onshore LNG production plants have enjoyed an excellent safety record. Offshore LNG production introduces more stringent requirements due to the congested nature of the plant, storage and personnel areas. 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 a nitrogen refrigerant greatly minimizes the hydrocarbon inventory and plant design simplicity and should ensure that the layout is relatively uncongested, with acceptable blast overpressures.

Quantitative risk assessment (QRA). QRA shows lower risk than many onshore LNG plants. Of course, accommodation location, 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 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. Safety studies and technical assessments should include determination of fire areas, gas dispersion modeling and personnel escape/evacuation, design accidental loads for all facility aspects and the effect of LNG on vessel structural steel.

Risk based assessments must show that risks are as low as reasonably practicable. Conventional engineering and safety assessments, including Hazard Identification and Hazard and Operability 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.

Regulatory issues. Classification society requirements have addressed statutory and regulatory issues for fundamental plant safety.[6,7,9] 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 a "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 designing safe LNGs 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. Therefore, it can be built away from the shipyard and this provides opportunities for capital cost savings and high-quality fabrication with established module suppliers.

Module limits are based on what can be fabricated (either local to the shipyard or locally to a port for transporting to the shipyard). A nominal limit of 2,000 tons is pragmatic to ensure crane availability. Cold boxes and rotating equipment packages are provided to the module fabricator fully piped, wired and tested. This philosophy is extended through all major equipment as far as practicable to simplify installation and hook-up of utilities, instrumentation and other services. Since vessel fabrication and topsides 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.

Overview. With uncertain gas prices and 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, lower cost and reduced time to first production. Evaluating critera that influence commercial acceptance of floating LNG production—safety, overall cost, performance, availability and delivery schedule—have led to selection of the dual nitrogen expander liquefaction process. This 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, and safety and environmental impact. These engineering studies have further reiterated that this liquefaction technology is an outstanding candidate for offshore LNG projects. **HP**

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