TARGETING AND ACHIEVING LOWER COST LIQUEFACTION PLANTS

AVOIR POUR OBJECTIF, ET REALISER, DES INSTALLATIONS DE LIQUEFACTION A UN COUT MOINDRE

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ABSTRACT

For more than a decade reducing the capital cost of liquefaction plants has been a key topic at most LNG conferences. Many ideas have been put forward yet costs have continued to increase over the years, despite improvements in liquefaction technology and increased economies of scale. Consequently very few new liquefaction plants have gone beyond the drawing board. The Trinidad LNG project developed by the Atlantic LNG Company of Trinidad and Tobago is the first to demonstrate that significant cost reductions can be achieved.

Squeezed by competition with pipeline gas in its sales markets and an established industrial market price for its gas supply, Atlantic LNG identified early on that for the project to succeed, cost reductions of 30 - 40% on recent liquefaction plants were required. A review of historical plant costs and several feasibility studies indicated that this was a possible, but difficult target to achieve. Driven by this need, the project team embarked on a highly focused combination of value engineering and life cycle cost evaluation, challenging many traditional standards and practices in the LNG industry. A simple reliable design began to emerge and as cost estimates came down, confidence in the project grew. The consideration of the Phillips process as an alternative to the industry leading Air Products process along with an innovative parallel Front End Engineering Design and contract strategy fueled a highly competitive EPC bidding process. Finally the necessary cost reductions were secured in a well defined lump sum turnkey contract.

The project was approved in 1996 and project financing secured in 1997. Construction is now well underway with hand-over planned for mid 1999. The Trinidad LNG Plant will be the first of a new generation of liquefaction plants providing reliability and safety at a cost that makes many more LNG projects possible.

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RESUME

Depuis plus d'une décennie, réduire les coûts d'investissements des installations de liquéfaction a été le sujet principal de la plupart des conférences sur le GNL. Plusieurs idées ont été mises en avant mais les coûts ont continué inexorablement à s'accroître au fil des ans, et ce, malgré les améliorations apportées dans la technologie de la liquéfaction et les accroissements des économies d'échelle. En conséquence, très peu de nouvelles installations de liquéfaction ont dépassé le stade de la planche à dessin. Le projet de GNL de la Trinité, développé par la société Atlantic LNG Company of Trinidad and Tobago, est le premier projet à prouver que des réductions considérables de coûts sont possibles.

Pressée par la concurrence avec le gaz de pipeline sur ses marchés commerciaux et un prix du marché industriel établi pour sa fourniture de gaz, Atlantic LNG a tout de suite constaté que pour faire marcher le projet, il lui fallait réduire les coûts de 30 à 40% par rapport aux installations de liquéfaction récentes. Après avoir revu l'historique des coûts des installations et plusieurs études de faisabilité, il s'est avéré que le but pouvait être atteint, même si cela était difficile. En gardant cet objectif en tête, l'équipe travaillant sur le projet s'est concentrée sur une combinaison de l'analyse des coûts et de l'évaluation des coûts du cycle de vie, remettant en question plusieurs des normes et pratiques traditionnelles de l'industrie du GNL. Une conception simple et fiable a commencé à prendre forme et à mesure que les estimations des coûts baissaient, la confiance dans le projet s'est accrue. Le procédé Phillips considéré comme une alternative au procédé phare Air Products de l'industrie, ainsi que la conception technique initiale parallèle et une stratégie de contrat totalement nouvelles ont alimenté un processus d'offres extrêmement compétitives pour l'ingénierie, l'approvisionnement et la construction. Finalement, les réductions de coûts nécessaires ont été assurées par un contrat clé en main pour une somme forfaitaire.

Le projet a été approuvé en 1996 et le financement retenu en 1997. La construction a maintenant commencé et la mise à disposition est prévue pour la mi 1999. Les installations de production de GNL de la Trinité seront les premières d'une nouvelle génération d'installations de liquéfaction offrant une fiabilité et une sécurité à des coûts qui rendront beaucoup de projets de GNL possibles.

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A BREAKTHROUGH PROJECT

The Trinidad LNG plant currently under construction by the Atlantic LNG Company of Trinidad and Tobago is set to be a landmark in the LNG business. It is the first grassroots LNG export plant to supply Europe or North America for more than 20 years. First production is scheduled for mid 1999, less than 7 years after project inception. This compares with a worldwide average of 14 years. [1] The project will be the largest single investment in the Caribbean islands and one of the largest project financings in Latin America.

The Atlantic LNG project also breaks the mold in a number of other ways. For the first time in 20 years a process other than the Air Products (APCI) Propane Pre-cooled Mixed Refrigerant Process has been used. Secondly at 3 million metric tonne per annum the plant is much smaller than any recent grassroots project. Furthermore, and perhaps more significantly for the future of the LNG industry, the Atlantic LNG project is the first to demonstrate that significantly lower cost liquefaction plants can be built in the 21st Century. The main purpose of this paper is to outline how this was achieved and can be achieved on other projects.

BACKGROUND TO THE PROJECT

The owners of the Atlantic LNG Company of Trinidad and Tobago are:

Amoco Trinidad (LNG) BV	34%
British Gas Trinidad LNG Ltd.	26%
Repsol International Finance BV	20%
Cabot Trinidad LNG Ltd.	10%
The National Gas Company of Trinidad and Tobago LNG Ltd.	10%

From the outset the project was market driven. Cabot LNG Corporation, owner of the Distrigas LNG import terminal in Boston, began looking for an additional supply source in 1992. The Nigerian LNG project, though now well underway, had faltered again and Cabot LNG began searching for alternatives. Trinidad offered a lot of potential and so Cabot began discussions with the Trinidadian government and companies with gas exploration interests in the area. The early involvement of a potential buyer undoubtedly speeded the project development process. The commercial development of the project has been described in other papers. [2, 3]

From the early days of the project, a team comprising members from all of the shareholders has managed the technical work. Through a Technical Services Agreement with the shareholders, Atlantic LNG will continue to draw on shareholder expertise as required during the construction and operation of the plant. However Trinidad has a high literacy rate and skilled workforce with a strong tradition of employment in the oil and gas industries and it is expected that most of the permanent staff will be Trinidadian.

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Bechtel International Inc. is the prime contractor for the project, with full responsibility for the engineering, procurement, construction, start-up and initial operation of the plant right through to satisfactory completion of the plant performance test. Following the test, Atlantic LNG will take over operation of the plant.

A consortium of ABN Amro Bank, Barclays Bank and Citicorp Securities arranged project financing. Due diligence was completed and a term sheet for project financing agreed prior to project approval in June 1996. Financial close was reached in June 1997. Financing is in the form of a $600 million Bank Credit Facility, supported by political risk insurance from the Export-Import Bank of the US and the Overseas Private Investment Corporation, a US government agency.

The LNG plant is designed to produce 3 million tonne per annum of LNG. The entire output of the plant was pre-sold under long term contracts, 60% to Cabot LNG Corporation in the Northeast USA, and 40% to Enagas S.A in Spain. Enagas is largely owned by Atlantic shareholder Repsol. Under a subsequent arrangement some of Cabot's LNG will be supplied to EcoElectrica in Puerto Rico.

Amoco Trinidad Oil Company will supply the gas for the project under another long term contract. A 40 inch diameter, 60 mile long offshore line will bring gas from two fields off the Southeast coast of Trinidad to the island. A 36 inch line then takes the gas the remaining 50 miles across the island to the LNG plant. Custody transfer metering is at the LNG plant.

The plant will use the Optimized Cascade Liquefaction Process licensed from Phillips Petroleum Company. The refrigeration compressors are driven by six General Electric Frame 5 gas turbines, supplied by Nuovo Pignone. The turbines and compressors are configured in parallel on each of the refrigeration circuits to improve reliability and flexibility and maintain a high level of plant availability.

Acid gas treatment is by diglycol amine (DGA) and there are the usual dehydration and mercury removal units. Propane, butane and condensate recovered in the liquefaction process are sold via pipeline to Pheonix Park Gas Processors Limited, the local NGL processing plant. The LNG plant is almost independent of local infrastructure and generates it's own power. LNG storage is in two 102,000 m^3 double containment tanks designed and built by Whessoe Projects Limited. The tanks have a free standing 9% nickel steel inner tank with a concrete outer wall and a carbon steel roof. A 600 metre long jetty is designed to handle ships from 70,000 m^3 to 135,000 m^3 capacity.

UNIQUE CHALLENGES

Many LNG projects have the benefit of a large low cost reserve base. In Trinidad there was already a significant and well established industrial gas market with agreed long term gas prices in place. Whilst gas supplies to a LNG project might expect a volume discount they could certainly not expect to be secured at rock bottom prices when an alternative market was available. Additionally, the uncommitted proven gas reserves were low, with only about 2 tcf available initially, and since considerable new infrastructure was needed to exploit them, the cost of producing the feed gas would be high.

Far East LNG projects also have the advantage of supplying markets without competition from pipeline gas. With the main competition in these markets coming from alternative fuels, LNG has been able to command a premium price. Trinidad's location in the Atlantic basin means that its main markets are North America and Europe, both of which have large supplies of pipeline gas. New markets may be opened up in the future in the Caribbean and South America but these were not options for the initial development.

So with competition at both ends of the chain the project faced both higher than average feed gas prices and lower than average LNG sales prices. Limited reserves and market potential prohibited the traditional LNG project response of a larger plant and cost reductions through economies of scale. In addition the commercial structure of the project, with different interests in various parts the chain, required the LNG plant to be a profit making entity. Whilst the use of second hand shipping helped somewhat it was clear from the beginning that the only way to make a viable project was to develop a low cost liquefaction plant.

COST REDUCTION AND COST TRENDS IN THE LNG INDUSTRY

One of the major topics of discussion at LNG conferences for many years now has been reducing the capital cost of liquefaction plants. The number of papers on the subject is quite large and whilst most present some useful ideas the only concrete suggestion has been to build larger plants using larger gas turbine drivers. Shell published figures in 1992 showing unit cost savings of 20% from larger plants using two large Frame 6 and Frame 7 gas turbines, instead of four Frame 5's. [4] Whilst this saving sounds significant most of it is accounted for by the simple increase in capacity rather than any real capital cost reduction.

Recent papers support the view that larger plants and gas turbines are the way forward. For example Mobil stated the following in a paper for the Oil and Gas Journal in June 1997. "Considering that liquefaction technology is mature, future technological advancements in LNG manufacturing would most likely be focused on increasing the single-unit capacity of the major equipment to reduce the number of such units, that is, gaining from economy of scale." [5] Leading contractors and licensors also seem to agree, suggesting that train sizes will soon reach 4 million tonne per annum. [6, 7, 8]

However economies of scale lead to other problems. Whilst unit costs are improved total investment increases. Investments in the whole chain, from gas supply through liquefaction, shipping and importation can easily be US$ 4 - 5 billion dollars for a 6 million tonne per annum chain. [9] The sheer size of the overall investment, along with additional partners, customers and suppliers makes projects very difficult to develop. This is part of the reason why LNG project development times are so long and so few LNG projects have come to fruition. It is rather stating the obvious but significant reductions in capital costs would encourage the development of many projects.

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A 1993 survey of historical liquefaction plant costs revealed some interesting trends. Figure 1 shows the unit cost against plant capacity for a number of grassroots projects and expansions. Overall larger projects would be expected to have lower unit costs but this is not the case. Whilst within a particular project expansions gave expected unit cost reductions different projects bore no such relationship. Similarly there was no identifiable relationship between train size and unit cost.

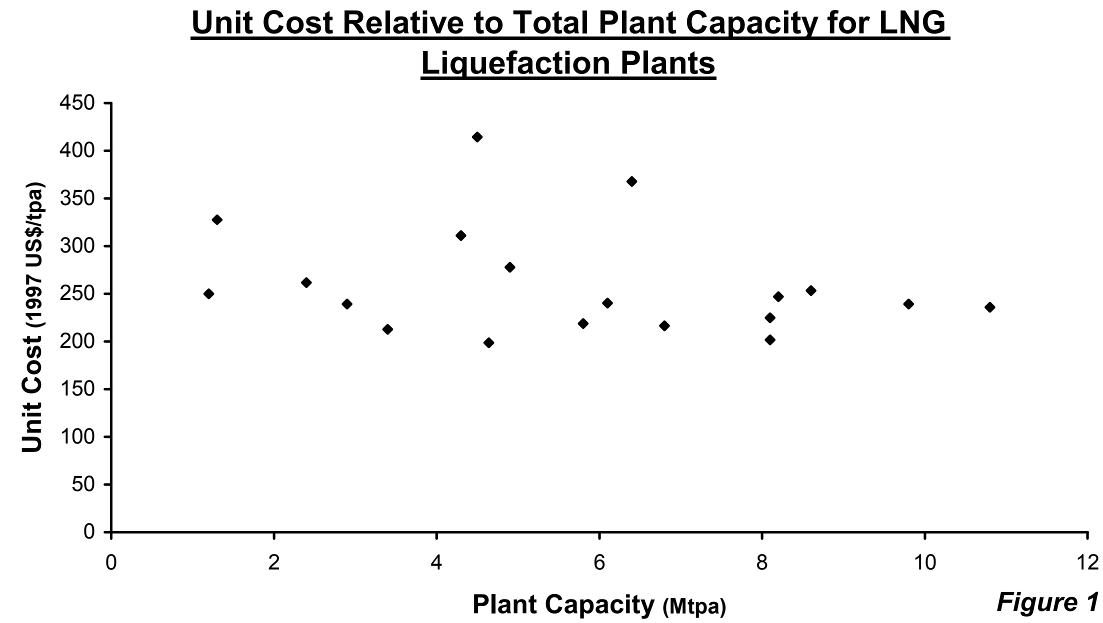

Figure 1

The only clear trend in the data assembled was that the real costs of LNG plants over the 70's 80's and 90's had been rising well above the rate of inflation. This is in spite of some substantial increases in train size and total plant capacity over the same period. Figure 2 shows the historical cost trend adjusted for a fixed plant size.

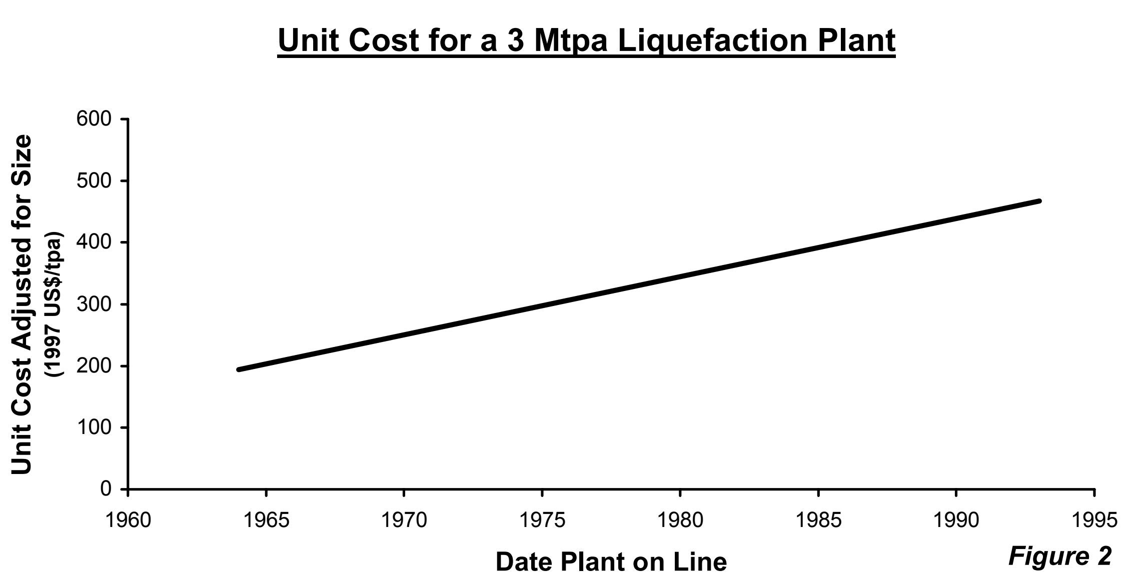

Figure 2

The unit costs in figures 1 and 2 are based on available data for EPC costs only, adjustments have been made for local labor costs, high carbon dioxide content, and differences in NGL recovery. General industry published escalation factors were used to bring all projects to a 1997 cost basis. In Figure 2 the cost has been adjusted using the formula in equation 1 to estimate the equivalent cost for a 3 million tonne per annum facility. Only the overall trend is shown to avoid reference to any individual projects.

$$Cost_a = \left(\frac{Size_a}{Size_b}\right)^x Cost_b$$

Equation 1

Where x is typically around 0.7.

This general increase in costs is in contrast to the normal trend that would be expected as a technology matures. For example "The general expectation is that as a technology reaches maturity, the capital cost (per unit of production) for a major project will tend to decrease (all other factors being equal)." [10] Whilst only approximate the above analysis attempts to make everything as equal as possible. The results are consistent with BP's assessment at LNG 11 that "The overall cost of LNG schemes appears to have been rising in real terms over the last 25 years, despite technical innovations such as large trains, large ships and gas turbines." [11]

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This analysis gave hope and focus to the project team in a number of ways. Firstly it indicated that a smaller project could be built at a reasonable cost and that economies of scale were not essential. Secondly it was quite clear that a number of earlier plants were built at the kind of cost required to make the Atlantic LNG project successful so we were not aiming for the impossible. Thirdly we recognized that to achieve a lower cost plant we would have to challenge the way that many recent LNG plants have been designed and built.

One other benefit of this historical cost analysis, that became significant as the project developed, was to highlight an often overlooked LNG project. The Phillips/Marathon Kenai LNG plant, though one of the smallest baseload plants, has one of the lowest unit costs, even after adjusting for the low ambient air temperatures in Alaska. Of further interest was the fact that it had one of shortest construction times of any project and is run by only 35 staff. [12,13]

EARLY CAPITAL COST TARGETS

Early generic cost estimates for the Atlantic LNG project, based for example on historical cost data or simple published estimating formulas, [14] indicated EPC costs of around US$1 billion for a 2.3 – 2.5 million tonne per annum facility. This was not unreasonable based on the kind of data shown in figure 2. At this production and capital cost anticipated financial rates of return were not just low, they were non-existent!

In the first instance plant capacity was based on Cabot's potential market in the Northeast USA. Economic analysis indicated that for a 2.3 million metric tonne per annum plant a capital cost of $600 million was required, some 30 - 40% less than these generic estimates. Feasibility studies from several leading LNG plant contractors indicated that this would be a very difficult target to achieve. However separate estimates by the project team, based on the same equipment costs and North American gas plant experience, showed that the target should be possible.

During these early studies the advantages of larger plants became obvious and options for a 3 million tonne per annum plant were considered. Whilst there were still some market and reserve concerns over a plant of this capacity it was recognized that a larger plant was necessary to give the project the best chance of success. Additional buyers were sought and the remaining output eventually sold to Enagas.

At the beginning of the Front End Engineering Design (FEED) phase a target of less than $750 million was set for the EPC contract for a 3 million tonne per annum plant including all supporting utilities, tanks and marine facilities. Initially some contractors considered this target to be overly optimistic but it was eventually bettered by every EPC bid received by the project.

The important issue here is one that has been made many times before - you can not hit what you don't aim for. Right from the beginning the project team knew the kind of cost that would make the project work and strove hard to achieve a reliable, safe design at that price. Merely working towards a general goal of reducing capital cost is insufficient.

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Specific targets need to be set and designers need to be aware of them and the business issues behind them.

LIFE CYCLE EVALUATION

Of course capital cost is not the only driver in project economics and capital cost reduction can not be an objective all by itself. Capital cost must be balanced with fuel costs, maintenance costs, and plant reliability. Safety and environmental issues are also of paramount importance. The full impacts of capital cost decisions must be analyzed over all aspects of the project and over it's whole life. Total cost of ownership or life cycle cost evaluation are common terms for this kind of assessment.

This is an important area for the operator to be fully involved. Understandably contractors are not aware of all the operational impacts of different options. Unless reliability issues are addressed properly and maintenance costs evaluated thoroughly it is easy to reach wrong conclusions. Also contractors, for obvious reasons, are often given limited knowledge of the economics of a project and have insufficient information to make correct decisions. As pricing becomes more flexible or is based on netback arrangements it is increasingly difficult to specify meaningful feed gas and product prices for contractors to use. Furthermore recommendations based on simple payback evaluations or even net present value economics can be wrong unless proper consideration is given to tax and financing issues.

To facilitate this life cycle evaluation senior operational personnel were assigned to the project early in the FEED phase. They also helped in the development of the design philosophies and advised on all operational issues. Simple economic models that matched the relative cost movements of more sophisticated models were developed and even provided to the contractors.

As commercial development of the project progressed and pricing and economic factors firmed up, the project team used full project economic models to evaluate potential options. On a number of occasions this evaluation altered clear recommendations from design contractors.

LARGE RELIABLE SINGLE TRAIN

The benefits of large LNG trains have been well established with one study showing cost savings of 14% for 2 trains over 3 trains of the same total capacity. [10] It was clear that a large single train was the best way to make the Atlantic LNG project viable. However this led to concerns about the reliability of a single train plant.

Early value engineering studies established that air cooling and gas turbine drivers were the most cost effective options for the plant in Trinidad. Given these choices, the main factor influencing plant availability is the gas turbines and compressors themselves. Apart from this, most other key equipment items on a LNG plant are static, in clean services and relatively reliable.

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The initial design philosophy was to use only equipment with two years proven experience in a similar service. However this ruled out several gas turbine drivers such as the Frame 6 and Frame 7 machines that were being considered for most projects at the time and for which significant cost savings were being claimed. Not wishing to eliminate any potentially attractive options, the decision was taken to extend the evaluation to a wide range of potential gas turbine drivers. The implications of less proven drivers were to be addresed by fully considering reliability and maintenance issues in the evaluation.

Figure 3 shows the results of this analysis. The relationship between project rate of return and plant capacity follows essentially a straight line. Economies of scale can be achieved just as easily with multiple Frame 5 gas turbine drivers as with Frame 7 and Frame 6 drivers. This is because the lower unit cost of the larger gas turbines is offset by reductions in availability and the additional costs of electric starter motors and extra power generation capacity.

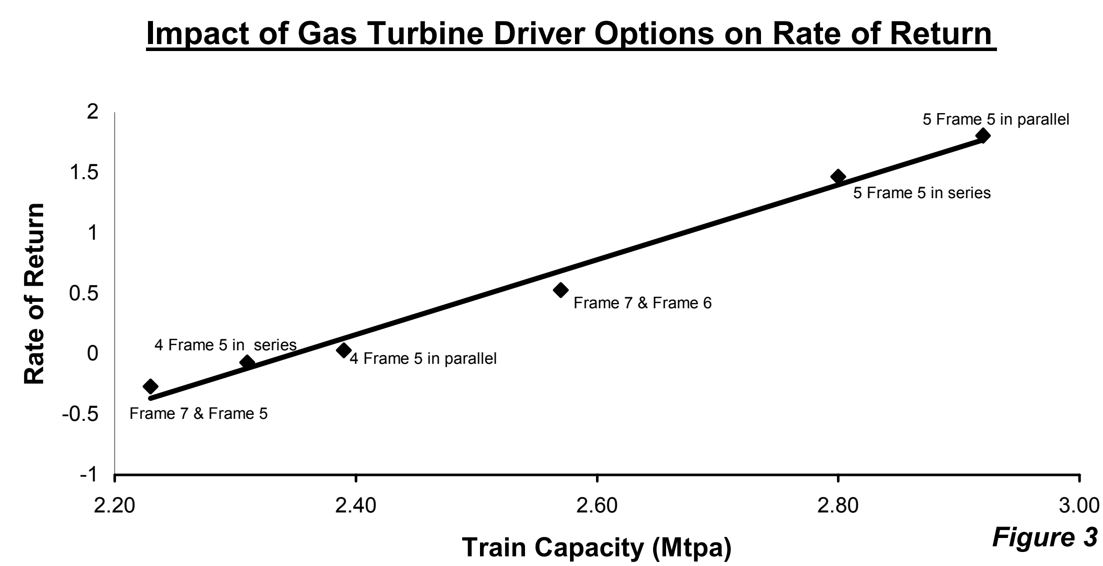

Figure 3

During this study it was realized that a significant improvement in overall plant availability could be made by arranging the gas turbine drivers and compressors in parallel rather than in series. When one compressor or gas turbine in a refrigerant loop shuts down the parallel compressor continues to run allowing the plant to continue operation at a reduced rate. Because heat exchanger approach temperatures improve at lower production rates and duty can be balanced between refrigeration loops one of two 50% compressors can still produce 60 - 75% of total plant capacity. Table 1 shows the production levels for some series and parallel compressor configurations. This table is for an APCI plant, with two compressors in the propane loop and three in the mixed refrigerant loop. The principle can be applied to any process. Availability here is defined as the net annual production divided by the design daily production multiplied by the number of days in a year. Production at rates above 100% is not considered.

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Remaining Plant Production	Series Configuration		Parallel
	One Train	Two Trains	Configuration
Loss of 1 Propane GT/Compressor	0%	50%	60%
Loss of 1 Mixed Ref GT/Compressor	0%	50%	75%
Overall Annual Plant Availability	90%	90%	93%

Table 1

The parallel configured single train has a higher overall availability than two trains with a series configuration. The additional capital cost for this option is small and more than offset by the improvement in availability. The parallel arrangement eliminates the possibility of a single machinery failure shutting down the whole plant and saves a lot of time when repairing a machine as the plant does not have to be completely shutdown and restarted.

Other considerations with Frame 6 and Frame 7 gas turbines were: increased scheduled downtime for the plant; higher maintenance costs; greater technical risk (at the time Frame 7 gas turbines had not been used in compressor drive service); and increases in construction schedule since full load string tests would be required prior to shipment.

A thorough life cycle evaluation was essential in making this decision and whilst the capital cost of multiple Frame 5 gas turbines and compressors was higher, this was more than offset by the higher overall availability.

It is worth noting that after making this decision, we realized that the Kenai plant, the only other single train baseload plant, has precisely this gas turbine and compressor configuration. It is reported that Kenai has never missed a shipment and has exceeded contract delivery volumes during its operation since 1969. [15, 16]

DESIGN MARGINS AND REDUNDANCY

It has been well publicized that most operating LNG plants are able to produce significantly more than their original design capacity. It seems that this has been due in part to over conservative design, probably driven by onerous contract requirements.

One benefit of Atlantic LNG's markets is that other supplies are available to the ultimate end users. A reliable supply is still very important but not as critical as in many other LNG trades. Atlantic's take or pay contracts have some flexibility in annual quantities before penalties are applied. This enabled a realistic view to be taken on design margins and redundant equipment, generally adopting the "design to capacity" approach.

Our basic philosophy was to use manufacturer's standard design margins and no more. Gas turbine derations, critical to the design of the liquefaction train, were based on General Electric published data, as was reliability and availability. Contractors were encouraged to apply standard design margins and licensors challenged to minimize guarantee margins.

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Redundancy of major equipment was approached using the life cycle cost principles described earlier. The impact of redundant equipment on plant availability was evaluated using the project economic model to see if the additional capital cost was justified. Of course any analysis of this type is dependent on good reliability data which is often hard to obtain. Sometimes sensitivities were run to find the breakeven point, and in some instances experienced judgment was used to overrule the bald economic facts, but only with good reason. In a few cases, instead of providing complete redundancy, the solution was to use two 50% or two 60% units, allowing the plant to continue to operate albeit at reduced rates. This is similar to the parallel gas turbine philosophy.

VALUE ENGINEERING

One well established technique for ensuring cost effective design and execution of a project is value engineering. Formal value engineering workshops were held during the early design phases. Participants were invited from shareholders, EPC contractors, vendors, sub-contractors, licensors and financiers. Individuals came from a wide variety of backgrounds from within the LNG industry and from outside. Experts in value engineering facilitated the sessions.

Whilst there was a preference for proven technology and equipment there was also a recognition that something different would need to be done to reduce costs. Brainstorming sessions emphasized that all ideas were acceptable and to be encouraged, judgement or criticism of ideas as they were generated was prohibited. Ideas at these workshops ranged from the obvious to the ridiculous, from the possible to the impossible. Huge lists of possible cost saving ideas were generated covering all aspects of project development from design to execution and operation. Every idea was ranked according to its potential, first on a subjective basis and later on its cost benefit to the project. This list of ideas was maintained throughout the design of the project and those with most potential evaluated in more detail at the appropriate time. Following the initial sessions a value engineering team, comprising specialists from both Atlantic LNG and the design contractor, continued this effort into the FEED phase of the project.

This formal approach was very valuable not only in identifying potential ideas but in encouraging us to continually challenge ourselves to do better and find more cost effective ways of doing things. Secondly the mere fact that we seriously considered other options encouraged traditional suppliers and vendors to improve their standard offerings.

INDUSTRY STANDARD SPECIFICATIONS

Whilst design codes and standards have not been discussed in many papers on LNG cost reduction, there is a general acceptance that project specifications can have a significant impact on the project cost. [17] Equipment costs can be increased substantially by onerous specifications with non-standard requirements that vendors have trouble meeting. In many instances the value of these requirements is unclear. Over the last

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decade many operators have been reviewing their traditional specifications with a view to making them more cost effective. The main thrust of this effort has been to use industry and vendor standard specifications wherever possible, only adding additional requirements where operating experience has shown them to be essential.

The basic set of specifications used by Atlantic LNG are based on specifications from one of the shareholders that have recently been through this process. Since equipment was likely to come mainly from the US the selected specifications were based on well known American standards such as ASME, ANSI, API, and NFPA. These specifications were augmented by one of the FEED contractors based on their LNG experience. This procedure had to be carefully monitored by the project team to ensure that unnecessary requirements did not creep back in. Selecting and developing an independent set of specifications like this allowed us to control standards and ensure the consistency of bids from different EPC contractors.

In many instances companies following this approach have set up alliances with high quality vendors. On this project we made use of alliances between vendors and the EPC contractor and vendors and the shareholders.

Another aspect of this philosophy is to maximize the scope of supply of major equipment vendors, allowing them to design and supply as much as they can of their auxiliary equipment and controls. Frequently the vendors have more experience than either the operator or contractor in their area of supply. It can be very cost effective to let the vendors do what they know how do to best and ensure that their detailed design is adequately verified through the review and approval process. Of course such vendors must be carefully evaluated prior to selection to ensure that they really have the experience for a particular scope of supply. [18] A detailed assessment of all equipment vendors was made prior to bidding the EPC contract and a final pre-approved vendor list was built into the EPC contract.

With respect to safety NFPA 59A, "Standard for the Production, Storage, and Handling of Liquefied Natural Gas", was used as the main reference document. NFPA 59A sets out guidance for siting, layout, equipment fabrication and installation, construction and operation of LNG facilities. It includes provisions for spill containment and measures to protect persons and properties from potential hazards of LNG plants. NFPA 59A emphasizes the use of passive fire protection means such as layout and spacing. This philosophy was followed in the design of the plant. In most instances separation distances specified in NFPA 59A were exceeded. Other relevant NFPA and API recommend practices, codes and standards have been used as referenced by NFPA 59A.

Environmental standards and guidelines were based on local Trinidadian regulations, the World Bank and the US Environmental Protection Agency, whichever was the more stringent.

SAFE AND COST EFFECTIVE DESIGN PHILOSOPHIES

Even within such codes and standards a wide variety of designs can be acceptable. The emphasis in traditional FEED contracts is often to ensure that the designer clearly specifies requirements to other bidders rather than to find the most cost effective solutions. Recognizing that safety is of paramount importance, the challenge for our design team was to find simple and cost effective solutions.

One of the biggest areas of discretion for operators is in instrumentation and control. Modern technology in this area in particular makes it possible to do much more than was ever possible in the past. However many times there is no clear line of sight to any business benefit. Modern technology has often been used to do more rather than to do the essential things more cost effectively. More is not necessarily better, not only does it cost more, but there is more to go wrong, sometimes hindering rather than helping operations.

A comprehensive set of simple design philosophies was developed by Atlantic LNG to guide the contractors in their detailed design. These covered such areas as safety, environment, start-up and operations, hazard detection, fire protection, emergency shutdown and depressurization, over pressure protection and control. The overarching intent behind these philosophies was to accomplish our design objectives and meet the requirements of the agreed codes and standards, without sacrificing operational requirements and in as simple and cost effective manner as possible.

COMPETITION AND CONTRACT STRATEGY

Despite the size of conferences such as this one and the high profile of many LNG projects the LNG industry is relatively small, accounting for only about 4% of worldwide gas consumption. [9] There are only 13 operational sites and there are only a limited number of contractors with proven LNG design and construction experience. On the process side, the APCI Propane Pre-cooled Process dominates the market with nearly 90% of the total installed capacity and with no other process being used in the last 20 years. In the equipment area, APCI supply a proprietary spiral wound heat exchanger along with their process and in many other areas such as loading arms and compressors there are only a few viable vendors with the requisite experience in LNG service. This limited number of suppliers, along with the understandable reluctance of the LNG industry to try new things, has probably contributed to the price increases identified earlier.

At the same time as the project was undertaking its initial feasibility studies, based on the APCI process, Bechtel were finishing a debottlenecking project on the Phillips Kenai LNG plant in Alaska. Bechtel's renewed acquaintance with the Kenai plant which they had built back in the late 1960's made them realize that there was potential in the Phillips Optimized Cascade Process, a development of the more classical cascade process used at Kenai. Phillips also began to take more interest in licensing their technology and offered to make their process available to Atlantic LNG. Supported by the evidence from the historical cost data and keen to find ways of introducing more competition, the project team commissioned a separate feasibility study from Bechtel for a plant utilizing the Phillips process.

The results of the study were promising, but not conclusive and in order to keep options open it was decided to embark on parallel FEED efforts on both processes. The purpose of each FEED was to develop a definitive scope of work on which to base a firm lump sum bid. The FEED contract for the APCI process was bid competitively and awarded to a Joint Venture led by Chiyoda. Because of the alliance between Phillips and Bechtel, Bechtel was awarded the FEED contract for the Phillips process.

Management of the dual FEED presented some interesting challenges but was not unduly difficult. Firstly we required that the FEED work be done in Houston. Separate Engineering Managers controlled each effort and some discipline engineers traveled between both contractors to ensure consistent application of the design philosophies and specifications. Design basis and plant production were the same for both designs, but within that and the philosophies and standards, each contractor and licensor were given the opportunity to optimize the process as they saw fit. Confidential information was strictly controlled, but both contractors were encouraged to use any public domain or non-proprietary ideas to improve their designs.

The FEED contracts included provisions for the return of full EPC bids from both contractors. It is unlikely that the dual FEED approach cost more than a single FEED followed by several paid bids which was previously frequent practice in the LNG business. This unique approach had several benefits. Firstly it generated intense competition and encouraged optimization of the FEED design. Secondly it forced the project team to be heavily involved in directing and controlling the Dual FEED to maintain consistency, thus exercising more influence over the final design and ultimately the EPC bids. The FEED contractors were able to quickly produce good bids and any deviations and exceptions were readily resolved by the project team. The APCI FEED documents were used to obtain a third EPC bid from M. W. Kellogg, further enhancing competition.

Bid evaluation was only slightly different than normal. As usual the first priority was to ensure that the contract requirements and specifications were fully met by all contractors. Bid questions clarified submissions and costs were adjusted as appropriate. The unusual questions to answer were; "How should the differences between the two process be taken into account?"; and "What about the risks of using a less proven technology?" Risk management techniques, using Monte Carlo simulations, had been used throughout the project to assess, quantify and determine other risks, such as cost, schedule and site selection. The project team decided to apply this approach to the technology selection issue. Difficult questions were asked: "What things could go wrong? What would it cost to put it right? How long would it take? How likely was it?" From this, risk profiles were developed for each bid on outturn capital cost, start-up date, reliability, availability and production rate. In turn these profiles were used with the evaluated bid prices in a Monte Carlo simulation in the project economic model. This resulted in net present value profiles for each bid and allowed us to identify the bid with the highest confidence of the best return.

The inevitable question is; “Does the Phillips process cost less?” This is hard to say. There are of course many differences. The Phillips process utilizes an extra refrigeration circuit compared to the APCI process, but the cheaper plate fin heat exchangers and vessels, replacing the APCI main heat exchanger offset this. The Phillips process reduces the cost of some ancillary equipment, such as the boil off compressor, and most of the refrigeration compressor circuits are in carbon steel piping, reducing piping and insulation costs. [15, 19] However against this Phillips require a substantial license fee.

We believe that much of our cost savings came from the competition and optimization generated during the dual FEED and from the use of our design philosophies and standards. It may have been easier for Bechtel, working from the Kenai model and from other North American gas plant experience, to implement and estimate our design philosophies than it was for other contractors with more recent experience on other LNG projects. Bechtel and Phillips were clearly very keen to win our job and sharpened their pencils accordingly. However, their price is a real one that, suitably adjusted for local factors, could be achieved on other projects.

THE TRINIDAD FACTOR

This brings us to some purely Trinidadian factors that undoubtedly helped to keep costs low. The location of the site adjacent to an old refinery and near to the town of Point Fortin is much less remote than the location of many recent LNG projects. There has been no need to provide a construction camp or other local infrastructure to transport the 2,000 workers required for the project.

Secondly, skilled construction labor is readily available in Trinidad at attractive rates and labor productivity is reasonable. Since construction labor is a significant part of the project cost, local labor rates and productivity can dramatically affect total project costs.

Trinidad is not too far in shipping terms from the competitive US equipment market. Bechtel have been able to set up a marshaling yard near Houston from which most of the equipment is transported by barge. This keeps freight costs down compared to many other projects.

Other factors helping capital costs are the quality of Trinidad’s natural gas reserves. We have a relatively clean feed gas with less than 0.5% carbon dioxide content and only traces of sulfur components; and the ability to eliminate fractionation and NGL storage by selling a mixed NGL stream to an existing nearby NGL plant. Finally and perhaps most importantly, the Government of the Republic of Trinidad and Tobago has always been very supportive of the project and able to facilitate the project timetable throughout.

SECURING THE SAVINGS

A vital part of our goal was not merely to demonstrate that a cheaper plant was possible but to actually build it, on time and within budget. This meant developing an EPC contract with a fixed price that included substantial guarantees and warranties.

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Financing terms preferred a lump sum turnkey contract and in order to ensure single point performance responsibility back to the EPC contractor it was decided to include commissioning and start-up responsibilities within the EPC contract. This was particularly beneficial in the case of the Phillips process and a very effective way of reducing Atlantic's exposure to start-up delays and production shortfalls from a less proven technology.

The final negotiations resulted in a strong fixed price lump sum turnkey EPC contract that aligns the contractors interests with those of the Atlantic LNG. There are performance guarantees backed by substantial penalties on plant production, fuel gas consumption and scheduled completion. On the plus side for the contractor there are bonuses for additional production, early completion and safety performance during construction. In order to encourage the EPC contractor to consider reliability and operability of the plant there are additional bonuses for sales above the guaranteed level during the plant's warrantee period.

With this type of contract it is essential that there is very good definition of the contract scope and that changes are not introduced after award. Otherwise there can be significant cost growth. A major effort was made to incorporate all requirements into the final contract documents. Technical due diligence was completed prior to final EPC award so that any issues could be incorporated if necessary. In fact, the design developed during the FEED was entirely satisfactory to the independent engineer.

In addition a team of independent experts carried out a separate review. This team consisted of experts from the shareholder companies and consultants with baseload LNG plant experience. Naturally a group like this had many comments on the design but their overall view was that the design was acceptable. Some specific recommendations to improve operability were incorporated into the design prior to EPC award.

CURRENT STATUS

The project team's vision statement is: "To be recognized for having set a new industry standard for engineering, procuring, constructing, starting-up and initial operation of a base load LNG Plant." We believe we are well on the way to achieving this. Engineering and procurement are complete and most major equipment is on site. Many of the major cost risks are behind us and cost growth to date has been low, well within targets set prior to EPC award. Whilst inevitably on a project of this size there have been some problems, nothing has yet arisen to indicate that the project will not be completed successfully, on schedule and within budget. Mechanical completion is scheduled for the end of 1998 and everything is on target for a first shipment in the 2nd quarter of 1999.

Whilst the skeptics (and this project has had many) will rightly argue that we are not there yet, and have still to complete construction and start-up, we are not complacent and well aware of the challenges ahead. A very experienced and substantial team of start-up and operating personnel are already in Trinidad preparing for pre-commissioning activities. We look forward to writing about our start-up experiences at the next LNG conference.

A second train is currently under consideration by the shareholders. Initial cost estimates look promising and some tie-in points have been incorporated into the design of the first train to facilitate the addition of future expansions.

CONCLUSIONS

The Atlantic LNG project demonstrates that it is possible to build significantly cheaper LNG liquefaction plants. Achieving this is not easy and requires a strong commitment from the operator to pursue cost reductions right from the outset of the project. Thorough economic evaluation based on accurate models must be undertaken, eliminating unnecessary design margins and redundancies. Simple industry standard design philosophies and specifications and effective competition between contractors and vendors needs to be developed. Overall this means that operators must be prepared to do things differently and find contractors who are willing to do the same.

The recent resurgence in the LNG industry is encouraging. For the first time for over 20 years, four grassroots projects are under construction at one time and future growth projections are more than double general oil and gas industry projections. [20] However clouds are on the horizon. LNG projects are getting more and more complex to put together with the chain extending through to power projects and with an extremely high overall capital cost investment required. Recent developments in gas to liquids technology are beginning to provide an economic alternative to LNG, which is commercially much easier to implement. [21]

If the LNG industry is to continue its current growth and head off the challenge of gas to liquids projects it is vital the lessons learnt on Trinidad are used on other projects. Larger plants built in the same way as before will not produce the required cost reductions. The Atlantic LNG plant shows the way forward for a new generation of cost effective and reliable liquefaction plants for the 21st century.

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The work reported in this paper was a team effort and many individuals, companies and agencies have contributed to the success that we look forward to. We would like to thank all members of the Atlantic LNG Engineering and Construction Team past and present, we could not have done it without you. All the contractors, licensors and vendors that we worked with made significant contributions too, thank you for sharing your knowledge and experience with us, we hope we were good students.

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