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LIQUEFIED NATURAL GAS FROM TRINIDAD AND TOBAGO: THE ATLANTIC LNG PROJECT

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Liquefied Natural Gas from Trinidad and Tobago: The Atlantic LNG Project

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About the Geopolitics of Natural Gas Study

Natural gas is rapidly gaining in geopolitical importance. Gas has grown from a marginal fuel consumed in regionally disconnected markets to a fuel that is transported across great distances for consumption in many different economic sectors. Increasingly, natural gas is the fuel of choice for consumers seeking its relatively low environmental impact, especially for electric power generation. As a result, world gas consumption is projected to more than double over the next three decades, rising from 23% to 28% of world total primary energy demand by 2030 and surpassing coal as the world's number two energy source and potentially overtaking oil's share in many large industrialized economies.

The growing importance of natural gas imports to modern economies will force new thinking about energy security. The Energy Forum of the James A. Baker III Institute for Public Policy and the Program on Energy and Sustainable Development at the Stanford University Institute for International Studies are completing a major effort to investigate the geopolitical consequences of a major shift to natural gas in world energy markets. The study utilizes historical case studies as well as advanced economic modeling to examine the interplay between economic and political factors in the development of natural gas resources; our aim is to shed light on the political challenges that may accompany a shift to a gas-fed world.

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About the Authors

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James Ball is a an internationally respected commentator, analyst and advisor on natural gas policy and strategy. He is President and Chief Mentor of Gas Strategies Consulting Ltd and of its EconoMatters Ltd.sister companies. He has been involved in numerous market studies including due diligence reports for lenders and sponsors of major gas projects around the world such as Qatargas II, Sakhalin Energy and RasGas 1&2 LNG as well as the Russia-Turkey Blue Stream project. He has specialized in LNG markets, mature market liberalization and new market development. He is a regular participant in the Alphatania gas management courses, has delivered many conference papers all over the world and chairs The European Autumn Gas Conference. He has also chaired key panels at the World Gas Conference, Gastech and ONS, including the WGC's Leaders' Forum in Tokyo in 2003. He received an MSc in Managerial Economics from City University Business School in London and a BA in Economics from the University of Colorado.

Liquefied Natural Gas from Trinidad and Tobago: The Atlantic LNG Project

Rob Shepherd and James Ball[1]

INTRODUCTION

In 1992 Cabot LNG, a relatively small Boston-based LNG importer and owner of the Everett LNG receiving terminal just north of Boston, approached the government of Trinidad and Tobago about developing a new LNG export project. Although three attempts had been made previously to develop LNG in Trinidad, nothing had come of them and the government had largely concentrated on attracting intensive gas-based industries to the country. The industries had come but had not greatly prospered. Cabot's approach came soon after the government had decided to liberalize its economic policy; new sources of revenue were badly needed. A memorandum of understanding (MOU) was signed by Amoco and British Gas (both had significant gas prospects in Trinidad) with Cabot, and the National Gas Company of Trinidad and Tobago (NGC) to promote an LNG export project, and they launched a feasibility study in 1993. Atlantic LNG, the joint venture company eventually set up to own and run the project, was formed in 1995. Sales contracts were signed with Cabot and with Enagas of Spain in 1995 for a total of 3 million tonnes per annum (mtpa) of LNG. Construction started in 1996. The first cargo, bound for Boston, was loaded at the end of April 1999. Design work and sales negotiations for a two-train expansion with a further 6.8 mtpa capacity (Trains 2 and 3) were started in early 1999 and construction started in 2000. Train 2 started up in August 2002 and Train 3 in May 2003. Train 4 is scheduled to begin operations in early 2006, while Train 5 is still looking for approval. The development has been rapid by the standards of LNG projects and judged a success for all parties involved.

This paper sets out to explore why the venture was so successful, what projects were competing and why they experienced different, often relatively less favourable fates. The question of competing projects in this case is quite complex and indeed the outcomes of competing projects appear different for different stakeholders – the buyers of LNG, the government of Trinidad and Tobago, and the project promoters.

It is necessary, however, to emphasise that wonderful as hindsight is, the project decisions must be viewed in the context of time they were made. For LNG, the early to mid-1990s was a very different time than today. The first projects in Algeria and Libya,

[1] Gas Strategies, Ltd. The authors would like to thank Meredith Williams for her work in creating the map.

launched in the 1960s and 70s, had suffered a series of setbacks and market reversals, and every subsequent attempt to launch an LNG export project in the Atlantic Basin had failed. The main exporter, Algeria, had only just begun revamping its own facilities after a period of lean demand. To the LNG business, export was a Pacific affair in which the Middle East had gained a small role. The achievement of the promoters of Atlantic LNG was truly mould-breaking and for very many in the LNG business, unexpected. This is not to diminish the achievements of the other Atlantic Basin project developed at a similar time, Nigeria LNG, which is discussed below, for, it too broke precedents. The LNG project launched in Trinidad and Tobago, however, had unique features both commercially and politically which were even more exceptional in the world as it was when the actions and decisions described in this chapter took place.

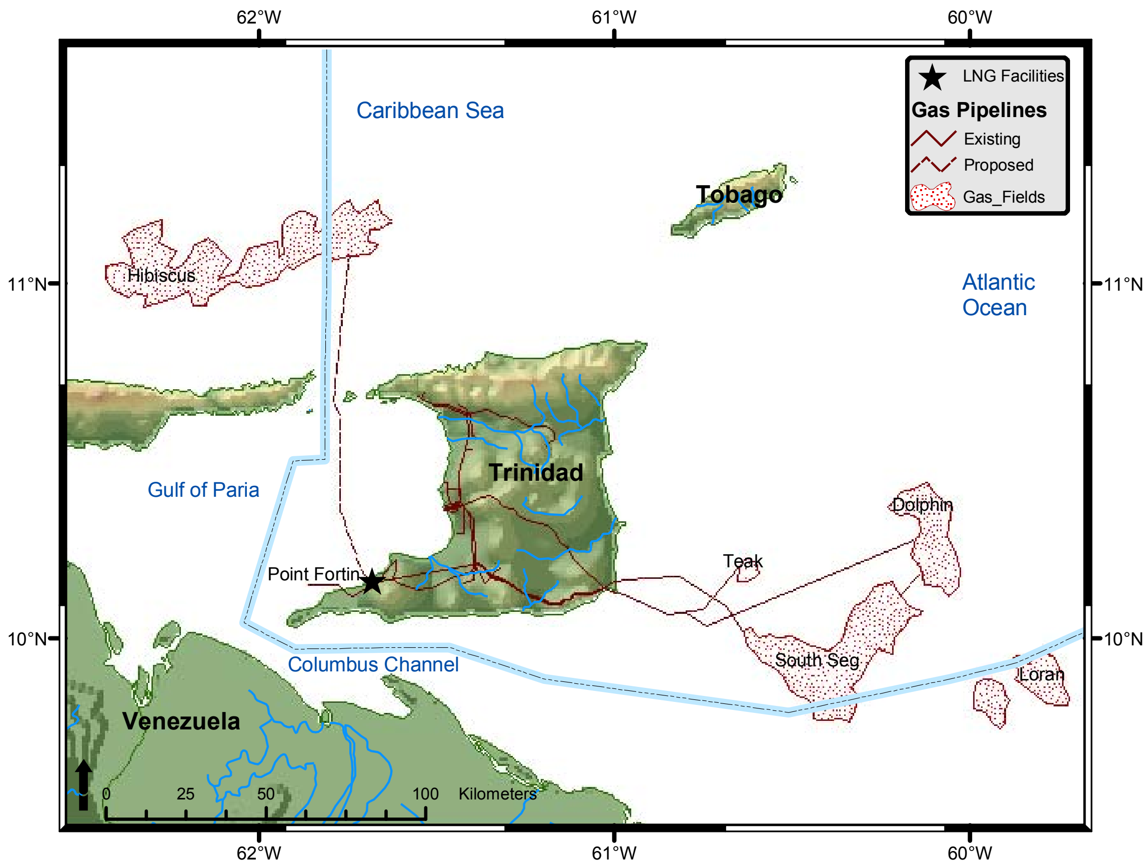
It also needs to be said that this project in many ways demonstrates that a host government can, via its policies, confer a competitive advantage to projects in its country vis-à-vis the polices of competing projects' host governments. Especially for the first project, the formative stage of a new LNG industry in a country, this can be a critical factor. LNG projects tend to be less geopolitically complex than international pipeline projects and particularly less onerous than projects in which transit countries are involved. They are, however, technically and logistically more complex, which makes them more elaborate to manage. They generally present a challenge for the host government, which is faced with balancing the long-term benefits of a successful project with the concessions and support needed (at least in the short term) to bring a project to life. LNG projects usually require preferable tax treatment compared with oil, and often compared with gas for local use as well. Such concessions to multinational companies are bound to be politically sensitive and require skilled negotiation to steer between the Scylla of offering too much and the Charybdis of a stillborn project. Furthermore, where there is local use and exports are a potential rival use for the gas, a local debate usually surfaces over whether this precious domestic resource should be "wasted" on foreign customers. The government will have to navigate this debate, often again and again. This debate arose in Trinidad and was resolved in favour of exports.

The Trinidad & Tobago government created a political and economic environment for the project that compared favourably with that faced by its would-be competitors, from its attitude towards outside investment to its political stability. Such factors were likely as important to the project's success as its commercial innovations.[2]

[2] A more enlightened Algerian government policy in the 1980s might well have preserved the position of Algerian LNG in the Atlantic market. Even if it hadn't, its new policy in the mid 1990s, which led to the plants being refurbished, came too late to prevent Nigeria and Trinidad filling the void in the market which opened up. Likewise, the various obstacles thrown in the way of the NLNG project by the Nigerian government, particularly in the early 1990s allowed the Trinidad & Tobago project to catch up and find a place in the market. The two Trinidad governments involved, by contrast, gave support when it was needed and stood out as the most hospitable of the three possibly contending LNG governments to LNG investment.

HISTORICAL BACKGROUND

Figure 1: Trinidad and Tobago Gas Infrastructure



Oil was discovered in Trinidad in 1886 and has been extracted from on the island since 1907. In fact, the steel drums characteristic of Caribbean music originated in Trinidad due to the excess of empty oil barrels discarded on the island. Since its inception, oil has been the mainstay of the island's economy. Gas was used only in oil operations until the late 1950s, when Federation Chemicals pioneered the use of gas for ammonia production. Most of the oil and gas production now comes from fields in relatively shallow water off the east coast of the island. A group led by Tenneco also discovered gas off the north coast of Trinidad in 1971. This gas lies under 500 feet of water and is much less rich in natural gas liquids than a typical east coast field.

The first attempt to develop an LNG project in Trinidad occurred in the early 1970s (very early in LNG history given that the industry was born in 1964) when Amoco and the

government spent two years negotiating with People's Gas of Chicago about the possibility of a project. Eventually the government decided that gas should be used to develop industry locally, and LNG disappeared from sight for a decade.
By the time of the first oil shock in 1973, following many years of low oil prices, the Trinidadian economy was in crisis, with a significant deficit, negligible foreign exchange reserves, and high unemployment (17% in 1970). Like with many oil-producing countries at that time, when many of the Gulf emirates were gaining independence, Trinidad moved to take closer control of the industry, acquiring BP's operations in 1969 and Shell's in 1974. The National Gas Company of Trinidad and Tobago was formed in 1975 to develop the gas market in Trinidad and was granted monopoly rights for the purchase, transmission, and sale of gas within the country. Trinidad never moved to complete nationalisation of the upstream oil industry, however.

The increase in oil prices in 1973 and again in 1979 produced a huge cash windfall for the island and initiated rapid economic growth. GDP grew from US$1.3 billion in 1973 to US$8.1 billion in 1982 and currency reserves reached US$ 3 billion in the same year[3]. The government set out to encourage industries that were intensive users of gas by developing suitable infrastructure – in particular the industrial area and port facilities at Point Lisas – and by investing directly in the industries themselves, although generally supported by management contracts with international players. Five gas-based projects were developed by 1985 and are shown in Table 1:

[3] World Bank (1994) World Tables 1994; Baltimore: Johns Hopkins University Press quoted in Barclay 2003.

Table 1: Gas Based Projects in Trinidad, 1985

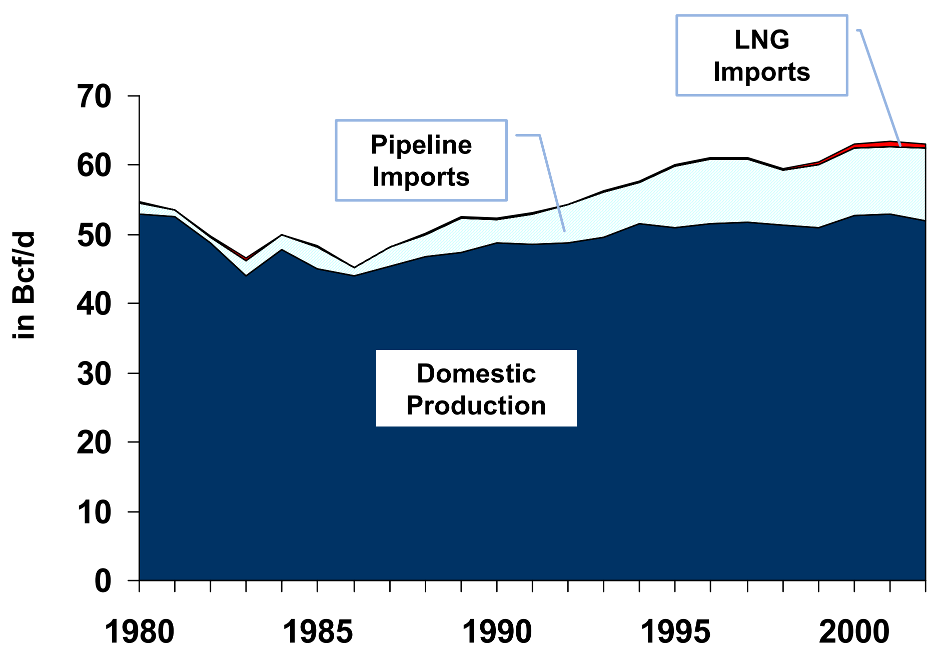
Company	Ownership	Start Up	Cost (Million US$)	Management
Iron and Steel Co. of Trinidad and Tobago (ISCOTT)	100% Government	1980	350	Local
Trinidad and Tobago Nitrogen Company (TRINGENI)	51% Government 49% W R Grace	1977	111.4	W R Grace Management and marketing
Fertilisers of Trinidad and Tobago (FERTRIN)	51% Government 49% Amoco	1982	350	Amoco Management and Marketing
Trinidad and Tobago Methanol Company (TTMC)	100% Government	1984	179.2	National Energy Corporation (Govt Owned)
Trinidad and Tobago Urea Company (TTUC)	100% Government	1984	117.1	FERTRIN Management Agrico Chemicals (U.S.) Marketing

Source: Farrell 1987, quoted in Barclay 2003[4]

[4] Farrell T.M.A. (1987) "Worship on the Golden Calf. An Oil Exporter's Industrial Strategy, Technology Policy and Project Planning During the Boom Years", Department of Economics University of the West Indies, St. Augustine, Trinidad quoted in Barclay 2003.

Trinidad was very successful in attracting large-scale industry (proximity to the U.S. market undoubtedly being a factor), but in a small country there are limits to gas consumption. At the end of 1982, production was running at about 3 bcm/year and consumption leveled off at around 4 bcm/year for most of the 1980s, but proven gas reserves stood at 310 bcm[5], sufficient for over 80 years consumption at the current rate. Faced with limited prospects of selling more gas, Tenneco attempted to promote an LNG project for the second time in the early 1980s. This was taken up by the government and discussed with several potential players. It was an unfortunate moment. The oil price hike of 1979 produced a worldwide recession in the early 1980s. Demand for gas fell in the U.S. (the main potential market for Trinidad LNG) and did not recover to 1980 levels for more than a decade.

Figure 2: U.S. Gas Supply & Demand



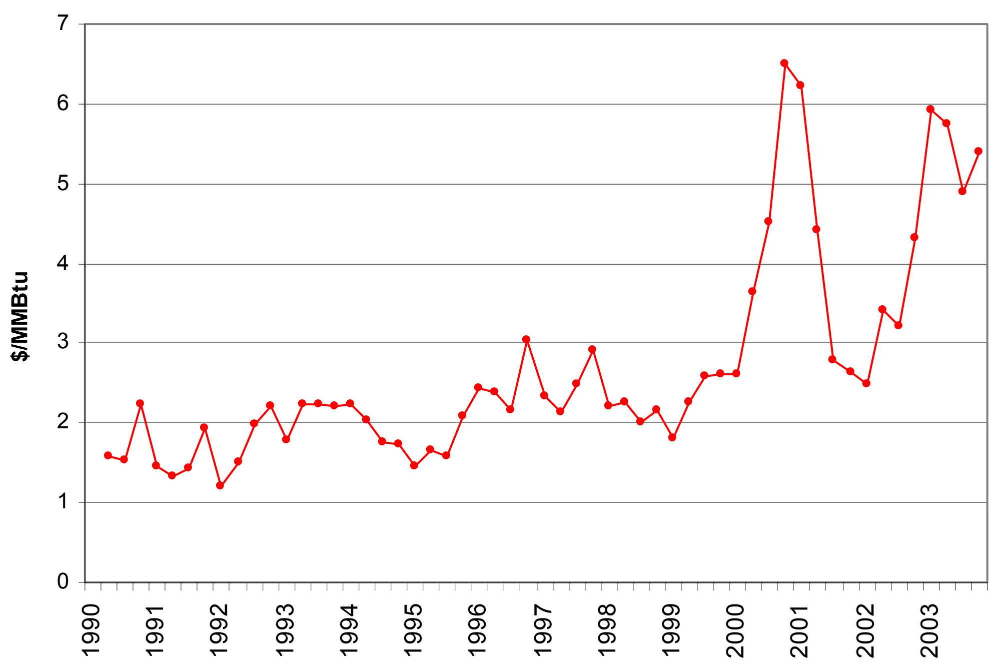
Source: Alphatania .

And, while 1979 was a record year for U.S. LNG imports, they declined rapidly thereafter and did not hit a higher level until a record of 1.4 bcf/d (10.65 mtpa) was recorded in 2003. Shortly after 1979, the contracts for Algerian LNG (the sole source of LNG supply in the Atlantic Basin at that time) collapsed, victims of U.S. market

[5] BP "Statistical Review of World Energy". www.bp.com.

problems and Algerian price aspirations. The U.S. was still left with an oversupply of indigenous gas. The stress of the oversupply was too much for the creaking regulatory system and precipitated the demise of most long term take-or-pay contracts between producers, pipelines and end users and a string of FERC orders that have become known as "deregulation." Nominal prices for newly discovered gas, which had under regulated well-head pricing been as high as US$10/mmbtu, fell steadily and remained (on average) around or below US$2/mmbtu until the mid-1990s, too low to make LNG a viable proposition, particularly as the projected costs of the Tenneco project were very high, based on north coast gas and the existing level of LNG plant cost. The second Trinidad LNG project came to nothing, quietly fading away in the early 1980s.[6]

Figure 3: Henry Hub Historic Prices

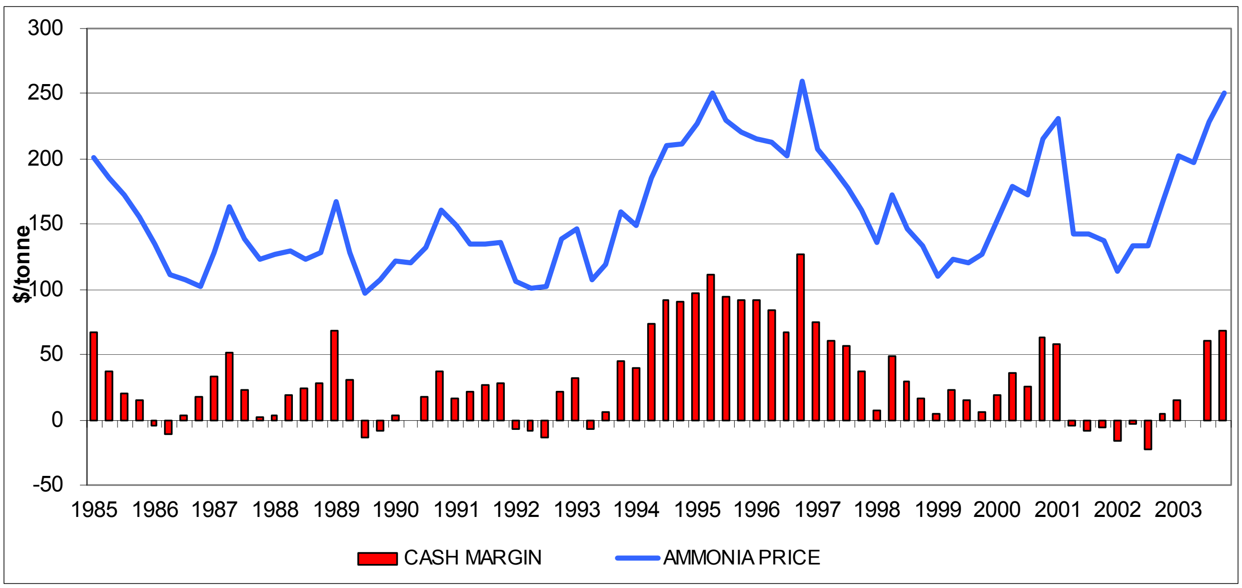


Source: Nymex

[6] This is not the place to discuss the history of U.S. gas prices and regulation in detail, so suffice it to say that while the price picture stayed in the US$2-.2.40/mmbtu range right into the late 1990s, the market situation in the mid-1990s was radically different to that at the beginning of the 1980s. At the time that this Tenneco project was envisaged, the gulf between projected cost and U.S. price and market opening was too great. The opening seized upon by the Atlantic LNG partners almost 15 years later was based on far better project economics and on the fact that LNG in Boston attracted a higher price than the rest of the U.S. market right up though the 1990s when Henry Hub became the marker price.

The performance of the gas-consuming industries in Trinidad provided little comfort either. The steel plant was late to be commissioned, experienced technical problems, and its output was subject to anti-dumping duties in the U.S. Investments in both ammonia and methanol plants turned out to be based on overly optimistic forecasts of price. These industries are very cyclical and only profitable in rare years except for the lowest cost producers.[7] The difficult world economic climate of the early 1980s was not a propitious time.

Figure 4: Ammonia Economics in Western Europe



Source: GasStrategiesOnline Pricing Service

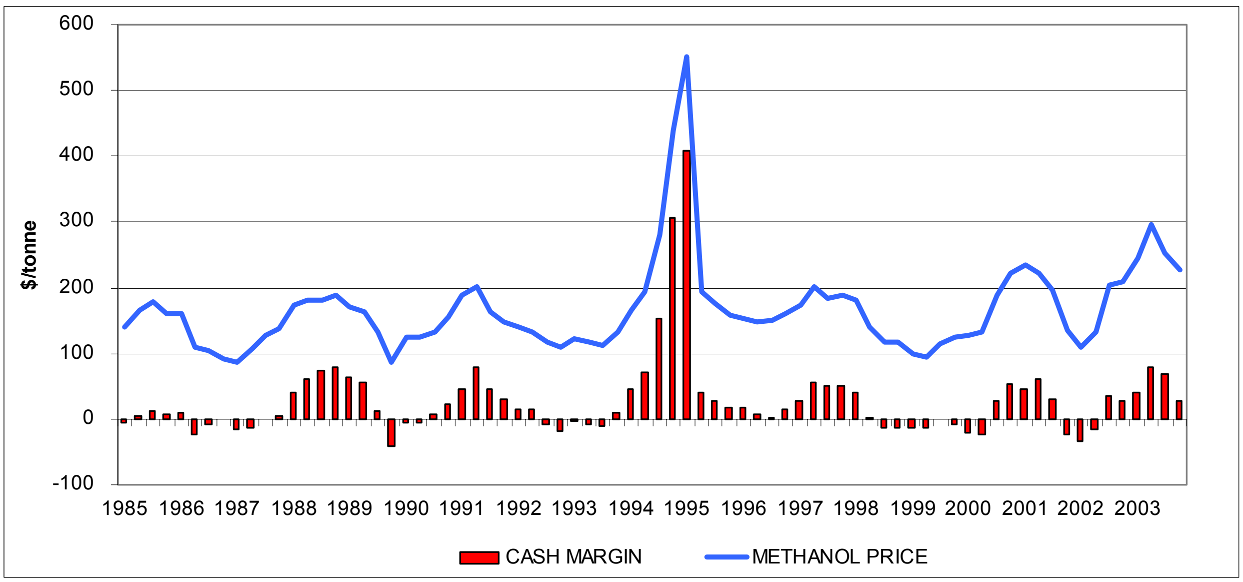
To add to the pile of problems facing Trinidad, oil prices collapsed in late 1985; Trinidad fell into a recession that lasted for seven years. GDP fell by an average of 4.7% per year from 1982 to 1989. Unemployment rose from 9.9% in 1982 to an estimated 22% in 1990. By 1990, foreign exchange reserves had fallen to US$492 million and external debt soared to US$2.5 billion. In 1989 the government of Trinidad and Tobago approached international lending agencies for funding. As part of the loan conditions, it agreed to implement stabilisation and structural adjustment programmes. The government set about liberalizing trade and foreign exchange, divesting state assets and encouraging foreign investment. This was in its early stages by 1992. The government published a green

[7] Barclay L-A.A 2003. "FDI-Facilitated Development: The Case of the Natural Gas Industry of Trinidad and Tobago" Maastricht: United Nations University, Institute for New Technologies.

paper on energy policy in November 1992, the key elements of which were summarized, in the view of one highly relevant international investor, Amoco as:

- Shift to natural gas to monetise the island's most plentiful resource;
- Promote competition within the energy industry to maximise the government's take and to attract new business to Trinidad and Tobago with the country's abundant supplies of natural gas;
- Privatize local industry to promote efficiency and repay national debt.

Figure 4: Methanol Economics in Western Europe



Source: Gas Strategies Online Pricing Service

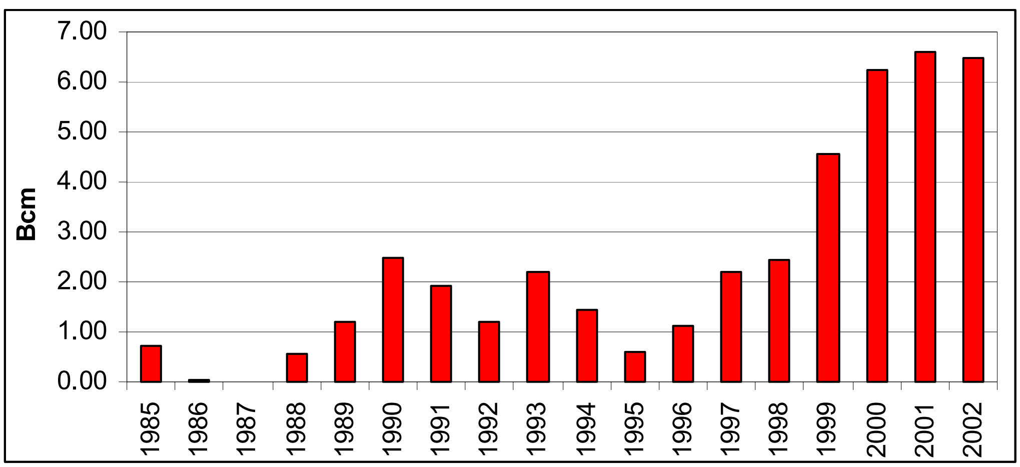
Amoco had a brief flirtation with a third LNG project at the beginning of the 1990s, this time to supply Puerto Rico, but it could not obtain satisfactory sales commitments. Such was the economic climate facing potential LNG project investors at the inception of the project which eventually succeeded.

THE COMPETITIVE CONTEXT AND THE ALTERNATIVE PROJECTS

After three false starts by Tenneco and Amoco, Cabot LNG initiated the Trinidad LNG project in 1992. That effort laid the groundwork for the Atlantic LNG project that exists today. Cabot was later joined in this endeavour by Amoco, BG and the National Gas Company of Trinidad & Tobago (NGC) and, once these partners had formed the project company in 1995, they were joined by Repsol.

Cabot LNG, with its subsidiary company Distrigas, was a small part of a much larger company and a small player in the LNG business. It owned the Everett LNG terminal just north of Boston and sold LNG in the highly seasonal New England market, mainly for peak shaving. It suffered from limited supply and was anxious to secure a new source of LNG. Only a trickle of Algerian gas (0.64 million tonnes in 1991) found its way into Boston, mainly in the winter to meet rising demand in the residential and commercial sectors. Since pipeline capacity into the northeast U.S. states was limited, prices would rise quite sharply in the winter months to a level at which Algeria was prepared to supply. Two long-term contracts existed between Distrigas and Sonatrach, but LNG was only supplied when the prevailing price was affordable for Distrigas as well as acceptable to Sonatrach; this situation usually existed only in winter.

Figure 5: U.S. LNG Imports, 1985-2002

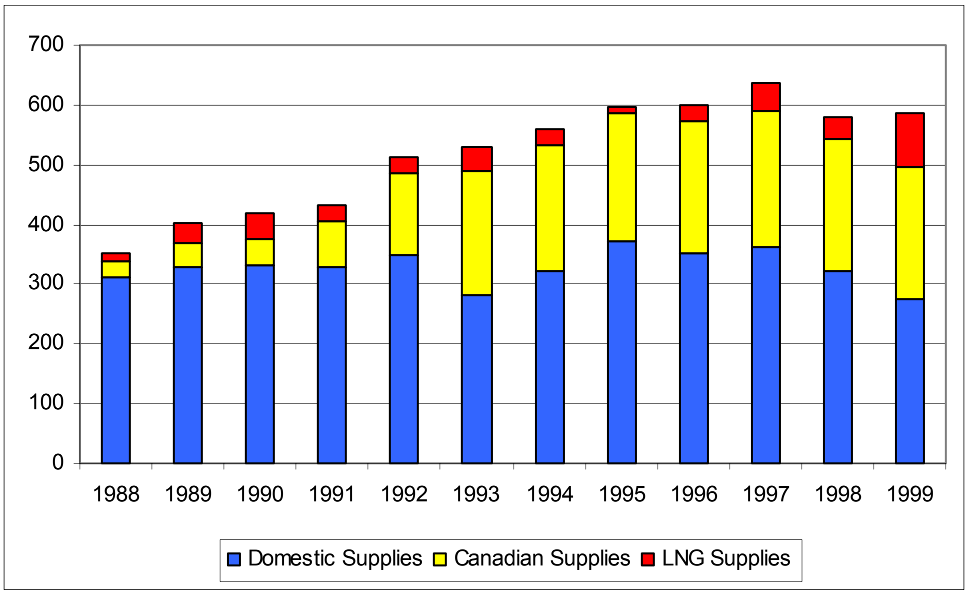


Source: GasStrategiesOnline

Demand was growing briskly in New England, from 9.9 bcm in 1989 to 14.6 bcm in 1992. Without new supplies, Cabot was threatened with losing market share. It also faced the threat that, if pipeline capacity into the northeast of the U.S. were significantly expanded, the premium price for gas in winter would erode. If this happened, Cabot would risk losing its Algerian supply and would have greater difficulty buying new LNG.

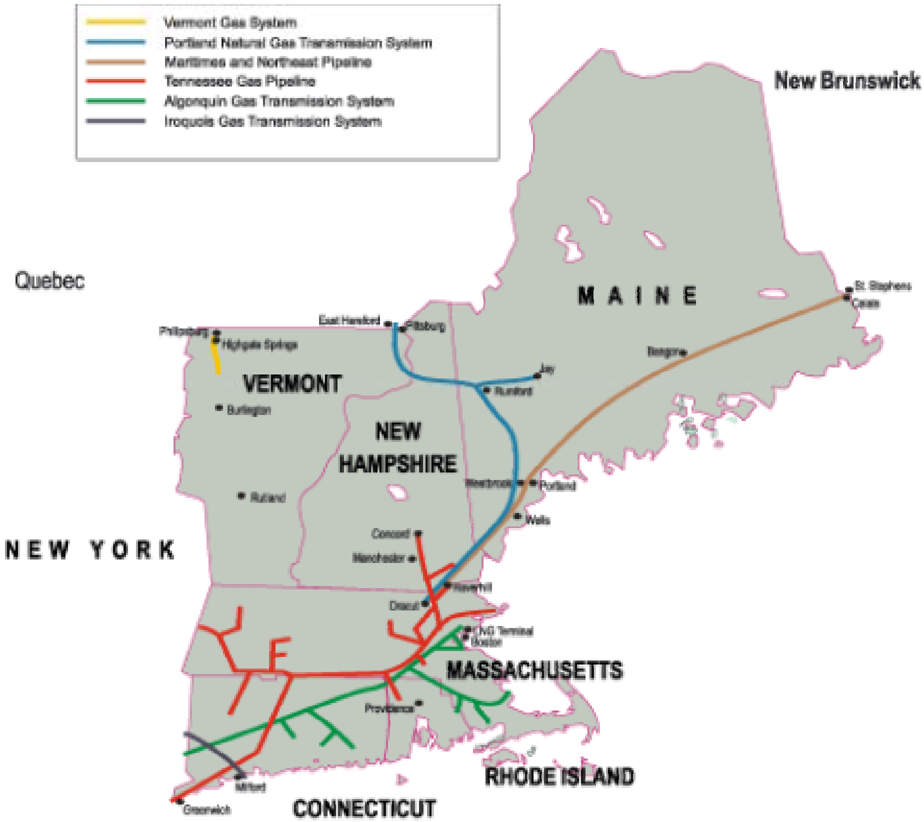
Since the company was dependent entirely on LNG this was a fairly stark proposition. Two new pipeline projects, the Portland Natural Gas Transmission System and the Sable Offshore Energy Project via the Maritimes and Northeast Pipeline from Canada were under consideration. Cabot wanted to acquire LNG rapidly in an attempt to preempt some of the pipeline supply.

Figure 6: Gas Demand in New England



Source: Natural gas consumption data from 1988 - 1998 came from EIA's Natural Gas Annual (DOE/EIA - 0131); 1999 consumption figure is an estimate from the office of Fossil Energy (FE) based on EIA data; Import data are derived from company filings made with FE.

Figure 7: Natural Gas Infrastructure in New England, 2000



Source: Thomas Dukes, The Expanding Role of Natural Gas Imports in Meeting Increased Gas Demand in New England, North American Gas Trade.

Its main alternatives to Trinidad were potential new LNG projects in Nigeria and Venezuela, and at one point it signed up for Nigerian supply.
The driver for Amoco was the desire to monetise more gas resources in Trinidad and LNG, increasingly, looked like not only the best bet but the only bet. Furthermore, by adding the LNG route to its gas sales options, Amoco could diversify away from methanol and ammonia price risk.[8]

Amoco was by far the dominant gas supplier to the island with over 80% of the market.

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[8] As things turned out (with U.S. prices soaring after start up in 1999) it is easy to assume today that Amoco expected higher netbacks from LNG. At the time, however, LNG looked decidedly marginal and at best likely to achieve a similar price to producers as rival island gas projects. The real prize at the time was seen as significant extra volumes of sales.

Gas demand on the island had reached 6.1 bcm/year by 1993, with 1.4bcm/year being used for gas lift in Amoco's oil operations. Of the commercially traded gas, 1.3 bcm/year was used for power generation and 3.4 bcm/year by the various gas consuming industries. Amoco sales were 3.9 bcm/year. The only non-Amoco supplies had been the Pelican field operated by state-owned Trintomar, which was in decline. However, the first 0.25 bcm/year was now flowing from the Enron Kiskadee field under a new contract, signed in October 1992, which would build up to 1.6 bcm/year, primarily to supply the new Caribbean Methanol Company plant scheduled to start up in 1994. Furthermore, BG signed a contract with NGC in September 1993 for the supply of up to 2.8bcm/year of gas from the Dolphin field starting in 1996.

All of this acted as a wake-up call to Amoco. The company had become rather complacent about its position in Trinidad. It now realised that it could not expect to develop its full gas potential through island sales alone. Indeed, the desire of the government for competition meant that Amoco's share of the local market was likely to be eroded further. In addition, gas sales prices on the island were largely tied to the highly volatile methanol and ammonia prices, with which Amoco was not very comfortable.

A further complication was that in order to minimise costs, Amoco had developed the habit of not proving up gas reserves ahead of agreeing to sales contracts. Although Amoco believed at the time it was sitting on 226 bcm of gas resources, its proven reserves were only 31bcm at the end of 1993, insufficient to fulfill in entirety its latest 20-year NGC contract signed in 1991. It was, however, selling gas at well above contract volumes to compensate for the falling production from the Pelican field. Nevertheless, on the basis of higher reserve expectations, Amoco was very interested in developing the LNG option.

British Gas was in a similar frame of mind, although it had a weaker acreage position. It nonetheless held out hope of proving up more gas in the Dolphin field than it had sold and had a stake in the north coast discoveries, which it had obtained when it acquired Tenneco's upstream activities in 1988. For neither upstream company was the prospect of more island sales a real alternative to LNG; the scale and timing made the two monetisation routes complementary.

The PNM government under Patrick Manning also was anxious to see the development of LNG as well as local industry, although there were doubters in the country who thought that Trinidad would be better off concentrating on reserving gas for local development and employment-intensive projects. In fact, as often happens to gas countries when a new monetisation option is added, Trinidad has been able to do both. The prospect of LNG was a real spur to exploration and far more gas has been discovered than was expected. In addition, the move to link local gas prices to the prices of the end product chemicals produced using it has greatly reduced the risk of investing in downstream chemical plants as the price risk was effectively moved to the gas producer (which in turn was why Amoco was keen to add a different market outlet to its sales portfolio. As a result, 8 new chemical plants using gas feedstock have commissioned since 1995, and three more are under construction. Trinidad is the leading regional producer of methanol and ammonia. In the last two years of high gas prices in the U.S., methanol and ammonia production in the U.S. have effectively ceased, leaving Trinidad in a strong competitive position (albeit in a still volatile business). Thus, LNG has given it a double gain from high U.S. gas prices; gas-based chemicals are more economic to make in Trinidad and Trinidad's LNG attracts higher prices. Gas consumption on the island is now in excess of 1 bcf/d (10 bcm/yr). The country has seen a long period of sustained economic growth.

The final actor, Spain's gas monopoly Enagas, (whose majority owner at the time, Repsol, would later join the project as a partner) was brought in only after the project had decided to increase its scale to reduce cost and Enagas had successfully concluded a fast track purchase deal for the available volumes. Spain was also seeing rapid growth in gas demand, and the government was concerned about overdependence on Algeria, the source of almost two-thirds of its gas. Enagas was therefore encouraged to find alternative sources of supply, which for geographical reasons (isolation from the European pipeline grid and with its neighbor France a reluctant and expensive transporter of what gas it got from the north) meant, in reality, probably LNG.[9] Beginning with efforts to buy Nigerian LNG, it later looked to Trinidad while Nigeria lay in limbo, and Enagas eventually bought from both Atlantic LNG and Nigeria.

With markets in the U.S. and Europe, the most obvious alternative projects to Atlantic LNG Train 1 were Nigeria LNG and Venezuela LNG, both of which were being actively pursued at the same time. And, because the only viable market in the U.S. was seen as Cabot's small opening in the northeast U.S., the pipelines from Canada to the U.S. northeast were also a factor. In terms of partner perception at the time, this pipeline threat was a key driver. There was a strong feeling that unless they got LNG to Boston in the time window ending around 1998, both this market and its price premium would disappear. This perceived pressure was to have a key impact on the speed at which the

[9] Spain had both LNG supply and the new pipeline supply from the GME pipeline from Algeria, which thus supplied almost two thirds of its gas. Worrying about diversity of supply, for supply security reasons, the Spanish government let it be known that it would tolerate no more than 60% of total gas supply coming from one country. With one expensive source from Norway its only source of diversity with domestic supply about to disappear, Enagas has little choice but to seek LNG supplies and it was an early customer from Nigeria LNG. With Nigeria suffering a series of politically craven delays in the early 1990s, Trinidad became an ideal addition to the supply slate. Trinidad's partners knew they had to compete on price not only with other LNG, but also with Norwegian pipe gas. Only later did others in the Spanish market, wishing to compete with Enagas (whose sales activities are now conducted by Gas Natural), take the LNG route to bypass restrictions on Enagas pipelines.

Atlantic partners acted; their consequent breaking of many LNG project precedents, not least being the flexibility they offered to their buyers.

In the LNG market the Atlantic partners also had to secure markets before their competitors could fill them and this meant improving economics and concluding deals quickly.[10] The key alternative projects to Trinidad were therefore the two other LNG projects, but the actions taken by Cabot in relation to the pipeline threat was always in the frame. Also in the frame, especially at the beginning, was the fact that Cabot had signed up for LNG from Nigeria and had fought a long, drawn out battle to obtain ownership of one of the three laid up LNG ships which the U.S. Maritime Administration (MarAd) had sold. When other contracted buyers rolled over their contracts after repeated delays by NLNG, Cabot cagily neither cancelled nor confirmed its intentions.[11] In the event, LNG got to Boston before these pipelines, in early 1999, but the pipelines were built anyway. Cabot failed to renew its NLNG contract and the ship it had secured in the MarAd battle became the *Mathew* and by a twist of fate delivered the first Atlantic LNG cargo, five months ahead of the first from Nigeria.

Nigeria also launched in 1999. In the case of the Atlantic LNG's expansion with Trains 2 and 3, the main issue is why it waited so long and why Nigeria got its decision in to expand first (even if it did not start up first). U.S. oversupply – the "gas bubble"–had finally been used up by the end of the 1990s, and U.S. prices were high enough to attract LNG supply. The market therefore was no real constraint on expansion. We will explore the reasons.

OVERVIEW OF THE ATLANTIC LNG PROJECT

As an introduction to the discussion of the development of the project, and to provide a convenient reference, a brief outline of the project history is provided below.

Train 1

Atlantic LNG was developed as a single train LNG plant designed to produce 3 mtpa (around 4 bcm) of LNG for export plus 6,000 bpd of stabilised Natural Gas Liquids (NGLs). In reality it produces about 3.2 mtpa. The quantity of liquids is important to most LNG projects and can easily make the difference between an economic and an uneconomic outcome.

[10] Enagas, too, wanted to quickly conclude a deal when it began negotiations in earnest. Having had long drawn out negotiations with other suppliers and facing delays and requests to roll over its contract with Nigeria LNG, Enagas let it be known that it wanted to move more quickly than was customary in European gas purchasing at the time. The Trinidad partners were quick to act on the message.

[11] To read about the battle over the MarAd ships, see Gas Matters, March 1990, and, for the settlement, September 1990, page 11. This involved Shell chartering two of the ships from Argent Marine who bought them secure in the knowledge of the Shell charter, and Cabot agreeing to charter the ship it bought, then the *Gamma,* to NLNG for half the time. This never materialized.

The plant is located at Point Fortin in the southwest of the island of Trinidad. The final investment decision was made in June 1996. The plant started up in March 1999 and delivered its first cargo of LNG at the end of April of that same year.
It is owned by Atlantic 1 Holdings LLC, whose shareholders are BP (formerly Amoco, 34%), BG (26%), Spain's Repsol (20%), Belgium's Tractebel (formerly Cabot, 10%) and Trinidad's government owned NGC (10%).

The reported cost of the plant and its associated facilities is US$965 million, which was financed in part by shareholders, but largely through a US$600 million loan, US$391.4 million of which was guaranteed by U.S. Exim[12] and $180 million by the World Bank's OPIC. The lead managers for the commercial loan were ABN Amro, Citibank and Barclays.

Gas is supplied by BP-operated fields off the east coast of Trinidad, via a dedicated 36" line that traverses the island (design flow into the plant is 12.8mmcm/d of gas). The National Gas Company of Trinidad and Tobago owns the line, but the capacity and operation are contracted to BP.

LNG from Train 1 is sold on an f.o.b. basis based on two long-term (20-year) contracts. 60% of the offtake goes to Tractebel and 40% goes to Gas Natural of Spain (an affiliate of Repsol). Notionally, the Tractebel portion is for delivery to the Everett receiving terminal near Boston, and that of while Gas Natural (who took over the contract form Enagas upon the unbundling of Enagas as part of Spanish gas market liberalisation)[13] goes to the Huelva import terminal in southwest Spain. However, there is significant flexibility in the contracts that allows for the switching of destinations. A small portion of the Tractebel LNG is used to supply a power plant in Puerto Rico and significant quantities of gas supposedly destined for Spain have been delivered into the U.S. In the past two years, over 90% of Gas Natural's contracted volumes have ended up in the U.S.

[12] The involvement of US Exim had led some modern geo-political specialists wondering if Exim's involvement was inspired by a U.S. government desire to see a closer LNG supply project launched. In fact, Exim had already taken the gas and LNG plunge and was part of the financing group for the RasGas project from Qatar to Korea as well as backing Algerian gas projects. We saw its involvement more as being motivated by a desire to be part of the nearest LNG project to the U.S. being launched. This was not a move it needed to be pushed to participate in.

[13] It is worth explaining Repsol's role. When Enagas signed up for this LNG, its majority shareholder was Repsol, also the major shareholder in Gas Natural. Enagas gained an option to join the Atlantic project as a partner but this was exercised by Repsol. The following year, after Train 1 construction began, Repsol, began discussions with Amoco which led to it farming in to Amoco's Train 1 fields and upstream exploration projects, making it partner in what are now the BP-operated fields. This move was, however, a separate development and not part of the Atlantic-Enagas deal. Why did Amoco invite Repsol into the upstream? Perhaps it felt too exposed by the very large proportion of Trinidad and Tobago gas production it held, a percentage diluted by Repsol. But also, Amoco found the other partners in Atlantic reluctant to push ahead with Train 2&3, teaming up with Repsol would give it a natural ally in Atlantic LNG. Gas Natural, already a gas marketing subsidiary of Enagas and Repsol, became the Atlantic LNG buyer when the Spanish government restricted its activities to running pipelines.

The elimination of strict destination restrictions, common in all LNG contracts up to that point, was a key selling point for Atlantic, though the delivery profile that eventually emerged was not intended at the time the contracts were drawn up (Spain's prices then being higher). This flexible behaviour, perhaps arrived at because the project was co-promoted by LNG buyers and by newcomers to LNG supply, nevertheless stood in marked contrast to the approach its competitors adopted. Furthermore, it decided to launch with just one train, something no LNG promoter had considered since Kenai. This was because Atlantic was trying to capture what it thought was a small market niche; again, making it more sensitive to its buyers and perceived market than was customary.

In order to produce the LNG, the liquefaction plant itself uses the Phillips optimised cascade process. This is a development of the process originally used by Phillips Petroleum (now ConocoPhillips) at its Kenai (Alaska) LNG plant, which started up in 1969 supplying the first LNG to Japan. The process uses a three-stage cascade in which the feed gas is first cooled against propane, then ethylene, and finally against methane refrigerants in large plate fin heat exchangers. The refrigerant compressors are driven by six GE frame 5 gas turbines.

The liquefaction plant uses two storage tanks, each with 105,000 cubic metres of capacity and a 700 meter-long jetty, which are capable of accommodating LNG carriers with a capacity of up to 135,000 cubic meters.

The Train 1 project, driven by a time deadline and what it saw as a limited market, had unusually strong drivers for speed and cost reduction (the unit cost of two train plants up to then being lower). This resulted in a number of commercial innovations that led to greater flexibility being offered to buyers, to picking a competing LNG process (a result of the much more vigorous competition amongst contractors its contracting strategy provoked) and to project execution on a flattened schedule.

Trains 2 and 3

If the Train 1 process was driven by speed, that of the project to launch Trains 2 & 3 was characterised by a slowness almost guaranteed by the inability of the Train 1 structure to easily and quickly expand. Still, once the partners did agree, they moved with customary execution speed.

Trains 2 and 3 added an extra 6.8 mtpa of LNG and 10,000 to 12,000 b/d of NGL capacity. Train 2 started up in August 2002 and Train 3 in April 2003. Significant restructuring of the project took place between the time of Train 1 and that of the project for Trains 2 and 3. As a result, Atlantic 2/3 Company of Trinidad and Tobago Unlimited, whose shareholders are BP (42.5%), BG (32.5%) and Repsol (25%), owns Trains 2 and 3. The company reports the cost of expansion at US$1.1 billion, and this stage was shareholder financed.

The design feed gas rate for the two trains is 31.7 mmcm/d. Train 2 is supplied partly from BP acreage (50%) off the east coast of Trinidad and the remainder from BG-operated acreage (50%) off the north coast (NCMA). The holders of the NCMA acreage are BG (45.88% and operator), Petrotrin (19.50%), ENI (17.31%) and PetroCanada (17.31%).

Train 3 receives 75% of its supply from BP acreage and 25% from a mix of NCMA gas (as with Train 2) and east coast gas (ECMA) held 50% by BG and 50% by ChevronTexaco. A new 24" line constructed by BG brings gas from the north coast area to Point Fortin.

Trains 2 and 3 operate on a quasi-tolling basis and although Atlantic LNG is the f.o.b seller, the gas suppliers have entitlements to LNG production in proportion to their gas supply. NCMA has entitlement to 50% of the capacity of Train 2 and NCMA and ECMA have entitlement to 25% of the capacity of Train 3. This LNG is sold to the U.S., initially to Lake Charles but in due course was also to go to El Paso at Elba Island. (BG acquired El Paso's capacity at Elba Island in 2003 and has taken over the contract itself.)
BP and Repsol share the remainder of the capacity. The Train 2 capacity is sold to Tractebel for Boston (0.2 mtpa), Repsol directly (primarily for Cartagena in Spain) (0.64 mtpa) and Gas Natural (0.7 mtpa). Train 3 capacity is sold to Repsol (1.7 mtpa). A significant portion of this gas is sold to Gas de Euskadi (0.7 mtpa) and the Repsol/BP/Iberdrola power project, BBE (0.8 mtpa), in Bilbao, Spain; through the new receiving terminal in Bilbao which is owned by BP and Repsol (see 0).
The two trains are similar to Train 1. An extra 160,000 cubic metre storage tank was added, as was an extra loading arm to the jetty.

Figure 8: Ownership of Upstream Gas, LNG plants and LNG sales, Trinidad

	Upstream		LNG plants		LNG sales			
					(all per annum)		Contracted Destination	
Train 1 4 bcm/year		BP	10%	NGC	2.4 bcm	Tractebel	Boston	
			10%	Tractebel				
			20%	Repsol				
			26%	BG				
			34%	BP	1.6 bcm	Enagas	Spain	
Train 2 4.4 bcm/year	50%	BG	50%	BG	2.2 bcm	BG	Elba Island	
	50%	BP	50%	BP	0.3 bcm	Tractebel	Boston	
					0.9 bcm	Repsol	Cartagena	
					1 bcm	Enagas (Gas Natural)	Spain	
Train 3 4.4 bcm/year	25%	BG	25%	BG	1.1 bcm	BG	Elba Island	Arrivals at Bilbao
	75%	BP	75%	BP	1 bcm	Gas de Euskadi	1 bcm	GdE
					2.3 bcm	Repsol	1.1 bcm	BBE
							0.6 bcm	Repsol
			Shaded area indicates shipping organized by Enagas/Repsol					

Source: Gas Strategies

Note: Current owners shown. Amoco was bought by BP and Cabot by Tractebel. The Train 1 deliveries to Puerto Rico are contractually made by Tractebel, not Atlantic.

THE DEVELOPMENT OF ATLANTIC LNG TRAIN 1

When Cabot approached the Trinidad government in 1992, it had a requirement for about 2 mtpa of LNG, which is equivalent to a feed gas rate of some 8.5mmcm/d. Initial discussions were held with NGC on behalf of the government, but by early 1993 BG and Amoco had joined in the discussions; clearly it was unrealistic to hope to develop an LNG facility without the cooperation of the major gas resource holders. Development of a new Greenfield LNG project is an undertaking of almost unprecedented complexity (certainly within the oil and gas industry) involving as it does – simultaneously – major gas field development, the construction of large scale liquefaction plants and ancillary facilities for the recovery of natural gas liquids, provision of port facilities and ships. Investment in the whole LNG chain characteristically runs into the billions of dollars. The whole development is normally underwritten by long-term (20-year plus) take-or-pay sales contracts, with one or more overseas buyer. A new LNG project represents, above all, a management and organizational challenge even to the largest companies. This will only succeed with a supportive host government and with its institutional support. More LNG projects have failed as a result of management failures or lack of informed government support than for any other reason.

The group coming together in Trinidad had no experience developing LNG export facilities. Cabot was a small importer of LNG and was owner of a laid up 125,000 m^3 LNG ship (then named the *Gamma*, now the *Matthew*) that had been made redundant by the failure of the Algerian trade more than a decade before and which was half-chartered to Nigeria LNG (see above).

BG (as British Gas) had been a pioneer of LNG as a launch buyer. It was the recipient of the very first internationally-traded LNG when it took the first cargo of LNG at its Canvey Island terminal in the UK in 1964 and had played a significant role in developing the first LNG ships. However, North Sea gas had been discovered in the UK as the first cargo of LNG arrived and imports faded to a trickle in the 1980s and ceased in 1990. BG nevertheless still had one of the original ships, the *Methane Princess,* on charter to Enagas. In 1993 it also acquired two more ships that had spent 20 years working on the Alaska – Tokyo run for the Kenai LNG project, the first in the Pacific; these tankers were being replaced by two newbuilds. At the time, then, BG's only presence in LNG was as a ship owner.

Amoco and NGC had no experience at all, although each had considerable technical experience within its own sphere and Amoco had a very successful track record of developing major international oil and gas projects.

Not surprisingly, it took the group time to develop leadership. The first task was to establish the basic technical and economic feasibility of a single train plant with the relatively small capacity (even for a single train) of 2 mtpa. Conventional wisdom at that time was that a minimum economic scale for a new LNG plant was two or three trains with about a 7.5 mtpa total capacity. However, it looked most unlikely that there was a profitable market for such large quantities in the Americas or Europe even if the gas had been available. Furthermore, back then the economic benchmarks for LNG were all in the Pacific, where gas prices were substantially higher than they were likely to be even in the north-east U.S. (LNG price into Japan averaged $3.52/mmbtu in 1993 whereas the Henry Hub price was $2.12/mmbtu)[14].

Technical scoping studies were carried out, and by the end of 1993 it was clear that a larger plant –closer to 3 mtpa – was needed. Therefore, more sales than Cabot's 2 mtpa were required at the LNG prices that could be expected. The associated gas liquids, present in the gas from the east coast fields, would almost certainly be critical to the project economics. There was considerable nervousness about U.S. gas prices. By 1992, the NYMEX futures contract based on Henry Hub in Louisiana provided the marker price for all gas in the U.S. (gas price at other locations was the Henry Hub price plus or, as was the case for Lake Charles, in Louisiana, sometimes minus) a basis differential that bore some relation to the cost of transporting to, and the gas market conditions in the region of, the point concerned. In the northeast, positive basis could be high and winter prices in excess of US$3/mmbtu were not uncommon, but Henry Hub prices and basis were both volatile. It was not clear whether a long-term contract based on U.S. market prices would be financeable. The participants themselves also needed to have sufficient confidence in the pricing mechanism to invest.

Clear tasks in 1994 were therefore to design the plant in such a way as to minimise costs and to find a buyer for the balance of the volume. Very little attention had been given at that point to how the project should be structured. Cabot and NGC were far smaller companies than either BG or Amoco, but no shareholdings had been agreed, not least because it had not been agreed what the role and scope of a project company would be or even whether it would be a company or an un-incorporated joint venture like the North West Shelf Project in Australia. Would all the companies participate in upstream gas supply or, if not, how would the liquefaction company buy gas or choose between the competing ambitions of BG and Amoco? Did the project intend to sell f.o.b. or would it take responsibility for shipping and delivering LNG to its customers? Was the project viable under current fiscal terms? The government offered various investment incentives to new industries; what package should the project seek?

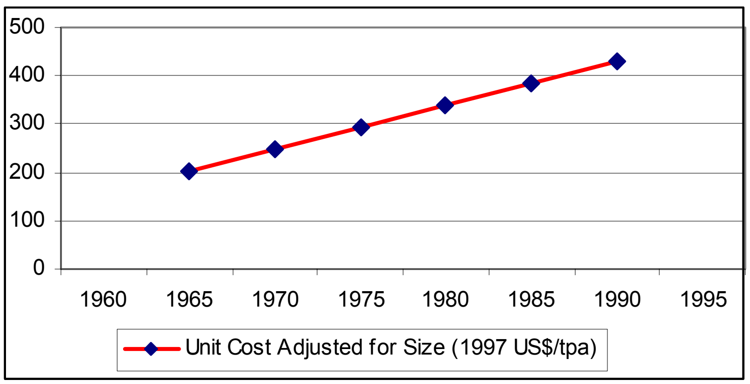
That all these issues were progressed more or less in parallel rather than first sorting, for example, ownership structure, turned out to be a key success factor for the project; it was also most unusual at the time and more experienced LNG promoters scoffed at the newcomers' approach. Nonetheless, as is common with most LNG projects, even those of the most experienced players, the technical work got ahead of the less tangible commercial and management problems but all the issues were progressed during that 1994 and 1995 period, again driven by the premise of the 1998 time window. That this turned out to be a false premise was immaterial as the multiple tasks achieved in 1994-1995 all contributed to its success. In the interest of a coherent narrative, we will deal with the various elements separately.

[14] BP "Statistical Review of World Energy". www.bp.com. A clear impression at the time was that the project had to be robust down to US gas prices of US$2/mmbtu.

Technical
The real technical success story of Atlantic LNG is cost reduction. The following section relies heavily on the paper given by David Jamieson, Paul Johnson and Phil Redding of Atlantic LNG at the LNG 12 conference in Perth in May 1998.[15] Much of the cost reduction was achieved by commercial ingenuity; it was not a case of a new technology breakthrough.

The most recent greenfield LNG plant to be commissioned at the time Atlantic LNG was designing its plant was the three train, 6 mtpa, North West Shelf in Australia, which made its first delivery to Japan in 1989 at a cost which was put at A$12 billion (about US$8 billion then). The real unit cost of LNG plants had been rising steadily since the first plant in 1964, rather surprisingly; the normal trend is that technical cost declines over time once the technology has become reasonably mature.

Figure 9: Unit Cost for a 3 mtpa LNG plant



Source: LNG 12 paper, ref 7.1

Initial analysis based on this trend suggested that the cost of a 2.3-2.5 mtpa LNG plant in Trinidad would be about US$1 billion (costs in this section are for the EPC contract for the LNG plant itself, not the full project cost); if the plant were to cost that much, the project would not be viable. To obtain an acceptable rate of return, it would be necessary to cut the cost to US$600 million. Feasibility work from experienced LNG contractors suggested that this would be very difficult to achieve, although the project's own analysis suggested that it should be possible. However, it also became apparent that there were major scale benefits from increasing the size to 3 mtpa. This gave some concern about the availability of extra market and about the adequacy of reserves (which were unproven at that stage). However, the larger size was chosen and used as the design basis developed with Kellogg (now) in Houston. By the time the front end engineering and design (FEED) contracts were let, the project set a target of US$750 million for the Engineering, Procurement and Construction (EPC) cost of a 3 mtpa plant.

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[15] Jamieson D, Johnson P, Redding P. 1998 "Targeting and Achieving Lower Cost Liquefaction Plants" LNG 12 Conference Paper, Perth, Australia, Des Plaines: Institute of Gas Technology, International Gas Union.

Considerable thought went into how to reverse the rising cost trend and getting back to the lower costs of the earlier plants. Two factors appear to be the main contributors:

1) Most LNG plants, particularly the more recent ones, had been built to serve the Japanese market. Japan has no real alternative source of gas to LNG (it has a minute quantity of indigenous gas). Far more emphasis had therefore been placed on security and reliability of supply than on getting the lowest price. Japanese power companies (the main buyers of LNG) have traditionally been permitted to pass on their fuel costs in their electricity tariffs. LNG plants were therefore built with very generous safety and capacity margins; it was quite common for LNG plants in the Pacific Basin to produce at 15% above their design capacity (North West Shelf, designed for 6 mtpa, produced 7 mtpa at the outset and was very simply de-bottlenecked to 7.5 mtpa).

2) There was very little competition to build LNG plants; only 13 LNG plant sites existed in 1994 and these plants had been built over a period of thirty years. There were very few contractors who built LNG plants (really only four: Kellogg, JGC, Bechtel and Chiyoda were very active and they often worked as joint ventures, Kellogg with JGC and Bechtel with Chiyoda). Furthermore, for the last twenty years, all the new plants had used Air Products' APCI technology. Sponsors had to take a technology license from APCI and buy the core piece of equipment; the giant main spiral wound heat exchanger that is at the heart of the process, as no other company could make it. As a result there was very little competition in constructing LNG plants. If one of the contractors prepared the front end engineering design (FEED), it generally acquired so much more detailed knowledge of the project than the competitors that it would almost inevitably win the EPC tender.

Amoco may not have had LNG experience, but it did have very up-to-date knowledge of upstream cost savings from the UK sector of the North Sea, which was becoming mature and very competitive. Amoco brought in an engineering manager for the project straight from a North Sea development project, David Jamieson. A major assault was mounted on all design factors that tended to increase cost.

And as so often happens with paradigm shifts, an approach from people with a wholly different perspective to that prevailing before in LNG simply tackled the problem in a new way. Knowledge of how it had been done before in LNG did not inhibit the team. As a matter of design philosophy, it was established that a single large train would have acceptable reliability provided that the equipment was configured in a particular way. To ensure that the whole train was not down it had twin drives, or shafts, so that no more than half the capacity was down at one time. It is a simple solution to the problem solved so many times in the past by adding a great deal of redundancy (one of the reasons for the "at least two trains" rule developers had imposed on themselves in the past). In any case, the planners decided that slightly lower standards of availability could be accepted (all LNG plants including this one have very high availability) than were applied to plants serving Japan as both markets supplied by Trinidad had alternative sources of supply. This allowed a more vigorous attack on costs; and the decision to contractually accept a lower availability was another example of both commercial and technical drivers being applied to the process. Ironically this plant, like all of its predecessors, turned on at well over name plate capacity; by then, however, the cost had come out.

The design margins of the design contractors were accepted without the owners adding extra of their own and similarly standard national (primarily U.S.) design codes were accepted rather than imposing internal corporate codes. Redundancy and complication were kept to a minimum.

Of all the cost reducing measures taken by the Train 1 pioneers, none had as great an impact on costs as what is now called the "dual FEED" strategy (defined below), and it was largely successful because the project was willing to accept a technology the rest of the industry had shunned for almost three decades and which, even as the plant was being built was predicted to fail by those who should have known better. The commercial part of the process was the tendering strategy.[16] The project's success in generating real competition between contractors had a dramatic effect. Key to the process was the principle that there were no favorites anywhere in the process.

The first shock was that Kellogg, after working with the project to prepare the design basis, did not win the competition to prepare the FEED; that went to a joint venture between Chiyoda and Hudson Engineering. In normal practice, this FEED would then have been put to tender and various contracting groups would bid slightly different prices and one would win. It was a sequential process and produced little competition except in lean times.

This time, things turned out differently. At this point the design was based on the APCI process, but while Trinidad was working on its design basis, Bechtel had just finished working in Alaska to refurbish and upgrade the Kenai LNG plant owned by Phillips and Marathon that had been operating since 1969. Phillips and Bechtel had realised the potential of the Phillips cascade technology used on the plant and decided to try to interest the industry in an optimised version. This came rather late in the day for Trinidad, but two of the sponsors, Amoco and BG, were very interested in exploring the possibilities to see whether there were cost savings or other benefits to gain from the newest version of the old technology. The only way, at this rather late stage, to assess this realistically was to ask Bechtel to carry out a parallel FEED exercise, and to pay for it. This would mean the project paying for two FEEDs and only using one. The extra cost was accepted and the second FEED ran in parallel to the first. Both FEED contractors had undertaken to submit full EPC bids following FEED. Kellogg was also asked to bid on the basis of the APCI FEED. The bidding process was highly competitive and won by Bechtel, using the Phillips process. The project was built on budget and set something of a new marker in LNG plant costs. (Shell and ExxonMobil were also pursuing cost reductions by different routes in Oman and Qatar, and there is a

[16] It should be noted that the NLNG project had also conducted a "dual FEED" process after if had been forced by the government to reject the first winning bid for political reasons, and needed to go quickly to construction once the FEED work was done. So here the projects were innovating in parallel, Trinidad improving on the NLNG process. Both achieved speed and efficiency and today dual FEED, with both the contractors paid for the FEED, is an accepted industry norm. But the acceptance of rival technologies made the Trinidad process more successful at reducing costs.

lively debate in the industry about whose plant cost least; Trinidad certainly scores for its combination of manageable scale and low unit cost). One clear strand of Trinidad's success was the determined delivery of a low cost project, which was vital to its economic viability.

Market and Shipping
Cabot was the first driver for the project, but in many ways it did not provide a conventional market for a new LNG project, let alone an ideal one. Most LNG supplies had been sold to traditional utility buyers in East Asia or Europe. In Japan, this meant the power and gas distribution companies such as Tokyo Electric and Osaka Gas, in Korea, KOGAS, and the (partially or primarily state owned) utilities such as Gaz de France Enagas (now Gas Natural) in Spain or Snam (now Eni gas and power) in Italy. These companies are characteristically large and impeccably credit worthy. They can buy LNG on long-term take-or-pay contracts with prices that are normally defined at the time of agreeing to the contract and which then are adjusted by contractually agreed pricing formula, basically in line with movements in oil prices during the life of the contract. Price formulae in most contracts can be revisited every three to five years to make sure that the adjustments are still in line with the market.

Cabot was very different. From the mid-1980s prices in the U.S. gas market were set by the spot gas market price. By 1990 this market was deep and liquid enough for the NYMEX futures exchange to launch the Henry Hub gas futures contract, one of the most successful commodity trading contracts ever launched, and it quickly became the market against which all U.S., and later North American, gas prices were traded. By the mid-1990s, gas prices had uncoupled from oil prices in any formal sense. A deep and liquid gas market had developed, and the Henry Hub NYMEX contract was one of the most liquid energy markets in the world. Nevertheless, gas prices were even more volatile than oil. All gas sold in the U.S., whether on short or long-term contracts, had little alternative but to accept U.S. gas market prices (instruments existed to allow prices to be hedged to provide a degree of risk management but this market was and is not liquid for a long period forward, certainly nothing approaching the normal life of an LNG contract). Trinidad required a long-term take-or-pay sale for two main reasons. Although the U.S. gas market is liquid, there is limited LNG receiving capacity and a new project would have to be assured that it could always physically get into the market. Furthermore, the project wanted to obtain project finance and undoubtedly the lenders would insist on normal LNG contracting practice. Cabot was prepared to negotiate a long-term take-or-pay contract provided that pricing was done on a netback basis from its market in Boston. This clearly protected Cabot from price risk and overcame some of the concerns about Cabot's relative lack of creditworthiness, at least compared with most of the usual LNG buyers. It did leave the project and its bankers with the need to make a forward estimate of U.S. gas prices for the life of the contract. This was particularly critical, as Boston was seen as a high price, niche market within the U.S. market because of its high winter demand and high differential to Henry Hub price. The project would not be viable on the Henry Hub price alone. This required in-depth study of the market and the particular conditions in the Boston area. Fortunately both Amoco and BG (at the time a major shareholder and participant in National Gas Clearinghouse – now Dynegy) were major players in the U.S. gas market and their experience, supported by consultant studies, provided the necessary confidence.

As has already been mentioned, Cabot raised the spectre of new pipeline projects threatening to enter the northeast and undermine the price differential. The successful instilling of this fear in the project mentality put pressure on it to move quickly and agreement in principle was in place by May 1995.

Since it had been established that the LNG plant would produce 3 mtpa, the search had started for another buyer. In reality this meant a European buyer, as the price in the rest of the U.S. market was too low and the next nearest LNG receiving facilities were in Europe.[17] This also provided a useful diversity of market risk as European buyers were more firmly in control of their markets and prices were often average higher there. The established LNG buyers in Western Europe were the monopolies in France, Spain, Belgium and Italy. Each country had a gas utility responsible for all the gas imports to the country, Gaz de France in France, Enagas in Spain, Distrigaz in Belgium and Snam in Italy. All had pipeline options as well as LNG and therefore LNG has to compete with pipeline gas (though Spain's options were limited by the government policy not to depend for more than 60% of its gas on one supplier and Algeria, its main pipe and LNG supplier was close to the limit). In those days before European gas market liberalisation had even begun, gas was purchased on long-term take-or-pay contracts with prices linked to oil product price (primarily fuel oil and gasoil – "No.2" to Americans), sometimes with an inflation or coal component. Most Algerian LNG and piped gas was price indexed against a basket of crude oil prices, however. Prices in Europe were somewhat higher than at Henry Hub although lower than Boston (average price of Algerian LNG into Spain was $2.26/mmbtu in 1994 when Brent crude oil price averaged $15.81/bbl and $2.32/mmbtu in 1995 when crude averaged $17.04/bbl) but the shipping cost to Europe from Trinidad was also about $0.30/mmbtu higher.

The project was under some pressure to move quickly and went out looking for European buyers in the second half of 1994. The shareholders were almost as inexperienced at selling gas in Europe as they were in developing LNG. Amoco and BG both had substantial sales in the UK, but the UK market is isolated from mainland Europe and has significantly different characteristics. What was wanted was a buyer who would take the lack of proven reserves on trust and who would be prepared to do a deal in significantly less than the leisurely year-to-eighteen months that it usually took to negotiate a full gas sales contract in Europe. Furthermore, the ideal buyers would be prepared to buy from a company (Atlantic LNG) that did not yet exist and whose exact shareholdings were unknown. This was a pretty tall order in the mid-1990s.

As the European buyers controlled their whole markets they were in a position to plan well ahead and not to put themselves under time pressure to buy gas. They wanted proven gas from credible sellers. Not surprisingly, the project did not make much progress in France or Italy. Spain was rather a different case. The Spanish market was

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[17] It is easy today to see that other opportunities existed in theory in the U.S.. But with speed of the essence and with other LNG promoters from the experienced Shell to Europe's Statoil having failed to break the regulatory log jam needed to open other terminals, the only real alternative at the time was Lake Charles in Louisiana where the price was too low and there was no ease of commercial agreement the project enjoyed in Boston. Also, Europe had terminals with both plenty of capacity and credit worthy buyers able to pay a higher price than the U.S. market then offered.

relatively new and growing rapidly. Furthermore, as has been mentioned, it relied almost entirely on Algerian gas and the Spanish government was not happy about this from a supply security perspective. Enagas had contracted to buy some Nigerian LNG but the Nigerian LNG project kept missing deadlines and contracts were kept alive by rollovers by the buyers. So, even though Enagas had signed up for Nigerian LNG, at the time of its negotiations with the Trinidad partners, the fate of that supply was uncertain. Trinidad supply, where at least there was a stable and supportive government, would be welcome on suitable terms and Enagas was willing to move quickly.

Furthermore, Cabot had a vision of much more flexible LNG trade in the Atlantic Basin. Cabot and Enagas, who had long had relations with each other as fellow buyers of Algerian LNG (not to mention as fellow would-be buyers of Nigerian LNG), rapidly established a letter of intent to co-operate on liftings and asked for considerable destination flexibility (most LNG sales, even if they are f.o.b.) require the LNG to be shipped to a defined unloading port, with any deviations to be agreed in advance with the seller. Spain has much higher winter than summer demand, which Enagas, with very limited storage, was struggling to manage it and the project could see the advantage of placing gas in the deeper, more open, U.S. market in summer even if this meant accepting a lower price.[18]
Enagas' parent, Repsol, also had ambitions to expand its upstream gas activities and saw an opportunity to gain a stake in the Trinidad project. By the summer of 1995, as delegates from the world LNG industry gathered in Birmingham for the LNG 11 conference, terms had been agreed for Enagas to buy 40% of the output and Cabot 60%. Buyer flexibility terms were accepted, as was the ability of Enagas to take a stake in the LNG project. The sets of terms were agreed with unusual speed and, as part of the process, the shareholdings of a new company, Atlantic LNG of Trinidad & Tobago, were agreed – all in parallel. (Note that Repsol's farming in to Amoco's upstream acreage was not the decision of the Atlantic partners and was not an option connected to its purchase contract, see note 12). At the same time, uncertainty still surrounded Nigeria LNG's contracts and while this would soon end, it was significant that Trinidad's partners had secured their deal in this period. [19]

Both contracts were on an f.o.b. basis; Cabot had a ship (whose once limited availability to NLNG was now cancelled) and Enagas had shipping experience (as did BG). BG had, in any case already chartered some of its ships to Enagas. The partners could see benefits in delivered (DES or CIF) sales, but Amoco, particularly, had a rather unhappy

[18] Spain's gas-fired power market had not then taken off. Furthermore this was the time when the Algerian LNG plants were undergoing refurbishment, cutting that source of winter supply, albeit temporarily. Enabling Enagas to take more of its volumes in the winter and Cabot to take more in the summer suited both parties and was the logic underlying the decision to give so much destination flexibility. In the end, however, the pattern was driven by price not season and most of the LNG goes to the U.S., to all parties' benefit, especially Spain's. Thus one of the great commercial contributions of this project to modern LNG trading was arrived at by accident and the party willing to "suffer" U.S. summer prices ended up the biggest gainer. Today in Spain, where the power sector is much bigger, we are approaching the time where the summer gas demand peak will be higher, as it has been for many years in Japan.
[19] For a contemporary account of the state of play between Atlantic LNG and Nigeria LNG at the time, see Gas Matters, June 1995, p1. It shares an author with this chapter. Contact info@gas-matters.com to find out how to obtain copies of the articles referred to in these notes.

experience with oil shipping and was doubtful about the commercial wisdom owning and operating ships.. After much debate it was decided to accept f.o.b. sales.

In summary, the marketing of Atlantic LNG Train 1 was done remarkably rapidly by most LNG project standards and this speed was a significant contributor to the success and speed of development of the project. At the time there was much agonizing about having a buyer as partner in the project (let alone two!) and whether the inevitable conflicts of interest could be managed. However, the presence of Cabot and later of Enagas (the Repsol representatives were often former Enagas LNG experts) gave considerable confidence in the marketing of the project and, far from being disadvantageous as far as sales terms are concerned, contributed to its success.

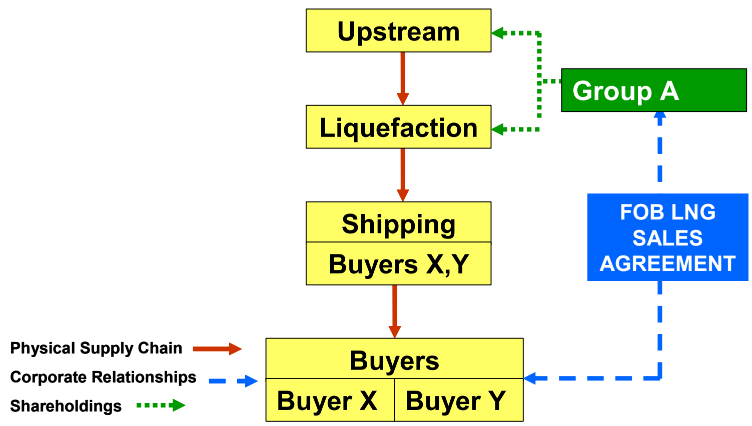
Project Structure
Perhaps the least successful feature of the Atlantic Train 1 development was the project structure. This is because it was easy to assemble at speed but very hard to expand upon, as the partners discovered in the painful process of launching Trains 2 and 3. That its participants have learned not to repeat the Train 1 model underlines the point. There are three generic models for organising LNG projects:

1. An integrated structure, in which the sponsors' shares in the project are in the upstream development and in the LNG plant; and the project sells LNG (from the plant in an f.o.b. project). (0).

2. An upstream transfer, in which the upstream owner sells feed gas to the LNG plant which in turn sells LNG. (12).

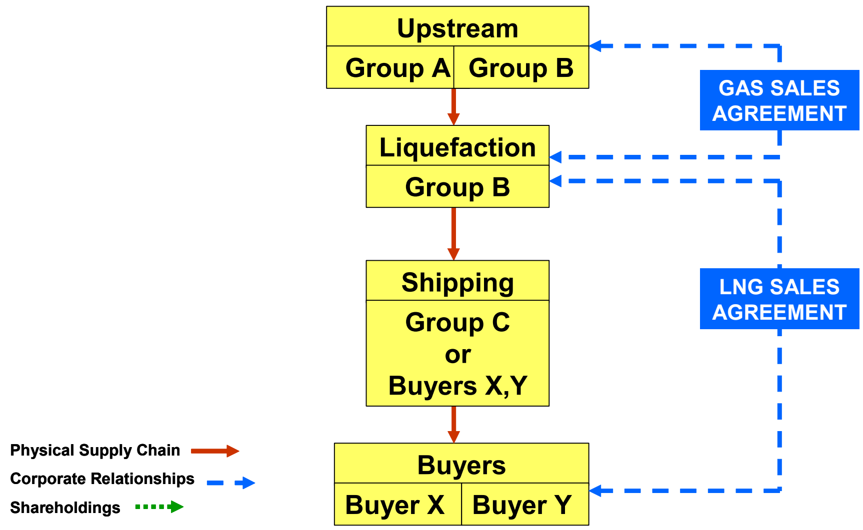
3. A tolling project, in which the upstream owner retains title to the gas up to the point of sale and pays a tolling fee to the owners of the LNG plant for the liquefaction of the gas and its redelivery. (0).

Figure 11: Integrated Project with f.o.b. Sales



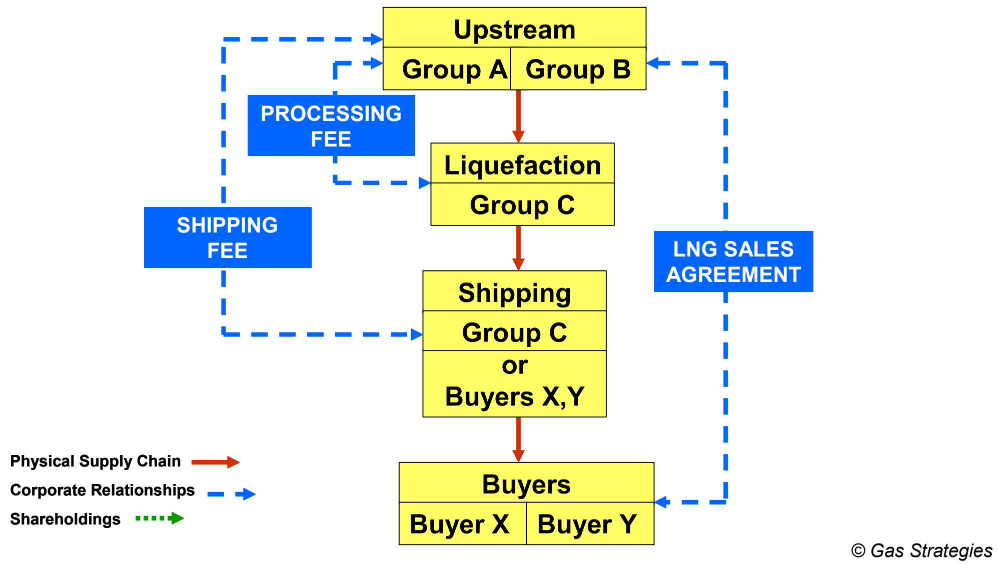
Source: Gas Strategies

Figure 12: Transfer Pricing Arrangement



Source: Gas Strategies

Figure 13: Tolling Arrangement



Source: Gas Strategies

Some form of each of these structures has been used successfully. The integrated structure (as in Figure 11) has the advantage of avoiding the difficult issue of transfer pricing for the feedgas into the LNG plant. It is easiest to arrange where there is a single field that will be used to supply the plant and where all the potential sponsors already have a share in the upstream, although it is quite possible to have a multi-field integrated project too.

The sale from the upstream into the LNG plant is perhaps the form found more than any other single type. It is simplest when there is a significant degree of common ownership between plant and upstream.

Tolling arrangements are rare. The Indonesian projects, however, have a quasi-tolling structure, in which the LNG plant is operated as a cost center and over the years a number of different gas fields have provided feed gas. This is particularly the case for PT Badak, at Bontang, Kalimantan, Indonesia which, in 2004, is still the largest LNG facility in the world. The fields receive a netback from the LNG sales price. The Indonesians also devised a satisfactory system for choosing which field's gas would provide the feed gas for the next expansion of the LNG plant. At Bontang, sales were coordinated by state company Pertamina, centrally pooled, and grouped into "packages". If two different fields (often with different operating groups) were in contention to provide feed gas to support new sales, then gas was taken from the two fields pro-rata to the quantity of reserves proved up and certified by each field that had not been used for an earlier sales package. Thus, if field A had 60bcm of proven reserves not already committed to an earlier sales package and field B had 30bcm, then 66.67% of the supply for the next sales package would come from field A and 33.33% from field B. This encouraged exploration by creating a "reserves race" between competing field owners, which suited the Indonesian government very well.

The situation in Trinidad was quite convoluted and no LNG precedent seemed entirely relevant. Two of the sponsors, Amoco and BG, had ambitions to supply gas from upstream; the other two did not. Neither NGC nor Cabot was financially very strong, but none of the partners was very clear about how they wished to finance the project. Cabot was also a buyer – an unusual situation for an LNG project.

The main issues to resolve were corporate form, shareholdings and gas supply. The project started with a completely blank slate on both issues and the fact that they are partly interrelated made them difficult to resolve. As far as gas supply was concerned, it was agreed relatively early that the distant and deep water gas off the north coast, where BG was the operator, should not be used for Train 1 on economic grounds. Not only would this gas be expensive to develop but it also was very dry with very little of the all important associated gas liquids (NGLs), that were present in most of the east coast fields. As explained above, the bonus of NGL revenues (NGLs can be sold like oil) can make or break some project economics. That left Amoco and BG east coast gas. Neither company had adequate proven reserves and therefore had no objective basis for deciding on their shares of upstream supply. Nor could they decide on a method of resolving the issue; neither company was really prepared to contemplate a formal reserves race where reserves proven by a specific date would set the basis for gas supply; this did not stop many abortive efforts during 1994 to agree upon shares before the reserves were established. Amoco had, nevertheless, an active appraisal program in 1994 that rapidly showed good results and proved up adequate reserves for the whole project. BG did not drill any wells until the beginning of 1995 and, rather unfortunately for the company, drilled two dry holes in succession. This finally resolved the supply matter in Amoco's favor, as the project could not afford to wait while BG proved up gas. Amoco therefore gained 100% of the supply for Train 1 but agreed along the way that BG should have a right to supply 50% of the gas for the first expansion and that north coast gas could be included.

The uncertainty over gas supply did not assist in resolving the corporate structure of the project and then the shareholdings. The project toyed with an integrated structure but this would require NGC and Cabot to be brought into the upstream and a system of cross shares between BG and Amoco fields to be agreed upon. Clearly, shareholdings would depend to a considerable degree on the gas contributions of BG and Amoco. There was little stomach for the complex negotiations required to harmonize the holdings in the gas fields and Cabot decided that, in any case, it had no experience in upstream gas and did not want to invest upstream.

The possibility of tolling was considered briefly, as it clearly provided one method of dealing with gas supply from different fields but (as recorded above) neither BG nor Amoco wanted a reserves race or similar objective way of resolving gas supply. Also, the project looked economically marginal and there was considerable nervousness about setting a tolling fee. The tolling fee should be protected from gas price fluctuations but this would increase the price risk upstream and it was clearly going to be difficult to agree on a fee. In the event, the attempt was not made.

By default, this left the only structure that stood a chance of being agreed reasonably quickly the common form of gas sales into the plant from upstream. Even with the basic structure agreed upon, it was still necessary to decide:

1. The actual corporate form of the joint venture and which affiliates of the shareholder companies would actually hold the shares. These are largely taxation-driven issues and were settled in favour of a company – Atlantic LNG of Trinidad & Tobago– incorporated in Trinidad and Tobago.

2. The individual percentage shareholdings.

3. The terms of the joint venture agreements governing the management of the company.

4. The terms of gas supply to the project company.

5. The means of getting gas from the fields to the plant.

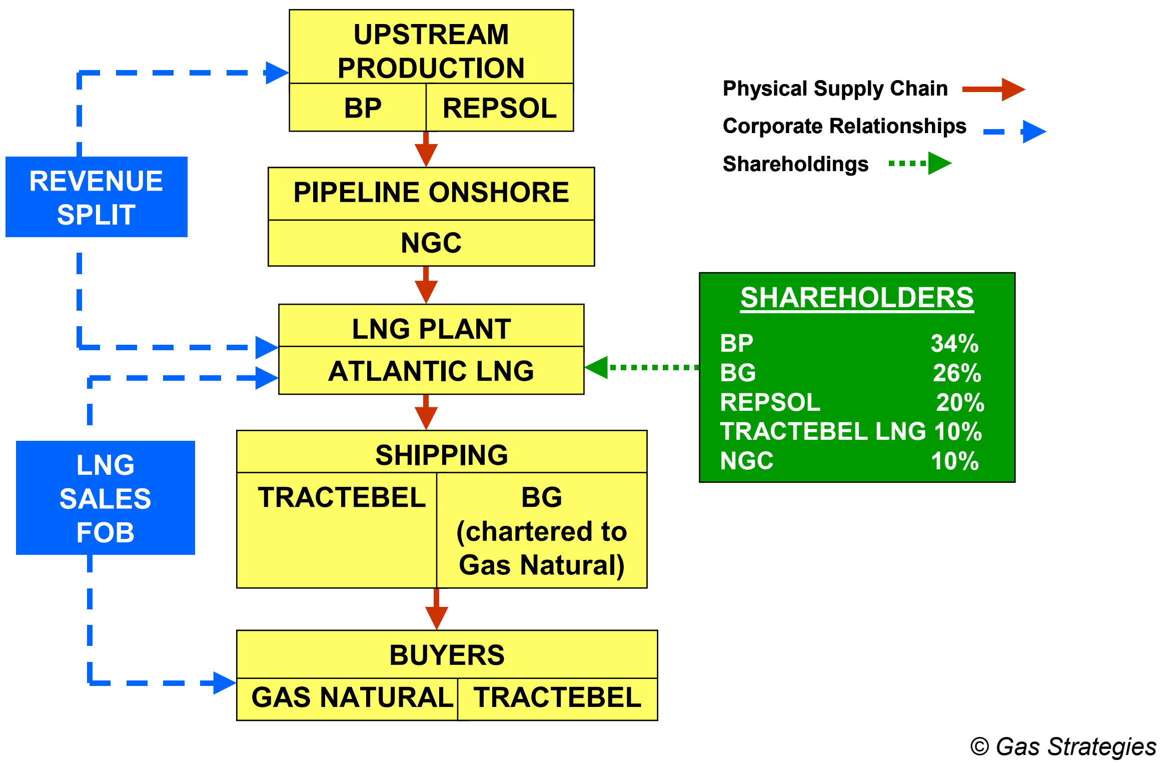
It was still not easy to resolve the shares each company should take in the project. Normally, BG and Amoco would have wanted their shareholdings to be roughly in proportion to their share of gas supply to the plant, but for a long time this was unknown and eventually turned out to be 100% Amoco. (This also raised the question of whether BG's upstream partners would be offered or would want a shareholding.) BG, with an eye to future expansion, did not want to opt out of the LNG plant. Amoco's original suggestion was that Amoco, BG and Cabot had between 25% and 30% each and NGC between 25% and 10% in recognition that NGC was a little reluctant to commit too high a proportion of its resources to the project. However, it soon became apparent that Cabot was also unlikely to want such a large share (although Cabot kept its options open as long as possible) and that Amoco was going to be the major (if not the sole) supplier of gas. It took considerable iteration (not least when Repsol negotiated its way into the project) to arrive at the current shareholdings: BP (formerly Amoco) (34%), BG (26%), Repsol (20%), Tractebel (formerly Cabot) (10%) and NGC (10%).

As a result of the protracted discussion of structure it was relatively late in 1994 before the joint venture agreements were drafted and active negotiation began (still before agreement on shareholdings and gas supply). This is inevitably a lengthy process and the JVA was not really settled until the terms of the Repsol entry were decided late in 1995 (as is common, the JVA and most of the other key agreements were signed in June 1996 as the final investments decision was taken).

In the meantime the project had no corporate entity to front sales negotiations or enter into contracts. In effect, the shareholders collectively stood behind any contracts let by the project for surveys and then front end engineering using a short agreement setting out each shareholder's liabilities.

With one LNG buyer and two shareholders with a share in the LNG plant, feed gas sales were always going to be on a strictly commercial, arms-length basis. Both government and Amoco had an interest in maximizing the into-plant gas price as government taxation is greater on upstream profits than on the profits of the LNG plant and Amoco, of course has 100% of the supply but only 34% of the plant. With a well established local gas market, there are also always political sensitivities over gas price. Even if the local market is saturated, it can be difficult to see gas going for export at a significantly lower price than local residents pay. Fortunately local prices in Trinidad were not particularly high and this never became too difficult to resolve, although it was the subject of some controversy and considerable negotiation between the government and Amoco, and later BP and BG. It was established quite early that the price of feed gas should be linked to the price of LNG so that price risks were shared between upstream and LNG plant. The resulting structure is shown in Figure 14.

Figure 14: Trinidad Train 1 Structure



Source: Gas Strategies

Finally, there was the issue of the trans-island pipeline; gas landing on the east coast would have to be brought across the island to the plant on the west coast. All gas transport on the island is carried out by NGC, which did not want to abandon the principle. The other partners were anxious to achieve maximum security of supply and wanted assurances that there would always be adequate capacity available to provide all the feed gas the LNG plant required and that gas could not be diverted to island supply. In the end it was decided that NGC should own the pipeline but lease the capacity to Amoco.

This section has provided a brief sketch of some of the main and more interesting structural issues that the shareholders in Atlantic LNG had to deal with. It is really only the tip of the iceberg; there are many more issues and agreements involved in developing an LNG project. The resulting structure was clearly workable for Train 1, but it was equally obvious that it would be difficult when it came to expansion as many of the original issues would be bound to resurface, particularly the gas supply and how economies of scale would be shared. This indeed proved to be a problem for Trains 2 and 3. What happened, however, was that the project got itself to a position to go ahead remarkably quickly in spite of an above-average number of contentious issues. This was chiefly because it managed to carry on the broad sweep of activities in parallel (e.g. letting engineering contracts before the company was formed, by a degree of improvisation rather than waiting for resolution of problems before moving forward).

Financing

Once the structure of the project had been put in place, reserves were proven and long-term take-or-pay sales contracts and acceptable economic returns could be demonstrated, obtaining financing was relatively straightforward. Gas projects, and particularly LNG projects, have a good track record and lenders are generally reasonably well disposed to them. The Trinidad project required finance, largely because the two smaller shareholders needed to raise money. For the larger investors it would have cost less to raise their own finance (as indeed happened for Trains 2 and 3). Amoco in particular had a strong balance sheet and impeccable credit rating. However a relatively modest 60:40 debt equity ratio was all that was sought.

The features of the financing that were specific to the project and relatively unfamiliar to lenders were:

1. Trinidad Risk
2. U.S. Gas Price Risk
3. The Phillips Cascade Technology
4. Inexperienced Sponsors

Trinidad and Tobago is a small country and therefore the level of exposure to the country risk was always going to be a factor. Trinidad has a democratic government and a good track record of orderly change of government following elections. The U.S. takes great interest in cementing its relations with the Caribbean and both US Exim and OPIC had significant appetite for Trinidad and Tobago risk. Between them they provided political risk cover for the bulk of the loan (US$571.4 million of US$600 million total debt). This aspect of Trinidad & Tobago contrasted significantly with Nigeria, which attracted little political risk cover at the time, and Venezuela, which was much less attractive than Trinidad.

Pricing in the sale to Spain was according to the conventional oil-linked European pipeline formula and thus relatively familiar to the lenders. However, no long term LNG deal which depended on the U.S. gas prices (Henry Hub) had been financed; there was no precedent at all. However, Amoco was the largest marketer of U.S. gas and British Gas also had a major U.S. gas trading operation (as part of Natural Gas Clearing House – Dynegy) so both companies were active in and clearly understood the U.S. market well. This combined with a positive consultants' report on the Boston market and its prices reassured the banks that the U.S. price risk was understood and acceptable. The netback pricing mechanism removed virtually all price risk from Cabot, which was a distinct benefit. Without this, Cabot's credit risk would have been of much greater concern. The liquidity of the market also gave comfort that the contracted gas volume could always be placed in the market (provided it could be landed) even if the price might be rather volatile.

The Phillips optimised cascade process was subjected to considerable technical scrutiny. In its favor was the very successful record of the original cascade process over nearly 25 years in Alaska and the proven competence of Phillips and Bechtel. Again, the risks were acceptable.

Although none of the partners were experienced in building LNG plant, they had taken advice from the leading contractors in the business and had recruited personnel who did have appropriate experience. Furthermore, both BG and Amoco had demonstrated strong track records managing major projects successfully, and managed to dispel the myth that LNG projects are uniquely technically difficult.

Although financing was relatively straightforward, limited recourse financing inevitably adds nearly a year to the schedule as due diligence is carried out and agreements are negotiated. It is not possible to do very much until the shape of the project and the market are pretty clear. Because Atlantic pulled so many things together in parallel, it was mid-1995 before there was sufficient clarity on reserves, sales, technology and project structure, all of which came together over a relatively short period. Until this time, drafting an information memorandum to start the financing process was not a realistic proposition. Even so, various issues such as the Repsol shareholding and in particular the project's agreement with the government had to be factored in along the way. The project was rather late in starting its negotiations with government, and financing was clearly dependent both on the agreed fiscal terms and on the project receiving the wide range of government permissions required. Commitment from the banks was received by June 1996 in the form of Heads of Agreement (still at a fairly early stage of detailed loan negotiations) at which point the project made its final investment decision. Financial close was finally achieved in June 1997.

Government Agreement

The project team came to negotiate with the government relatively late in 1995 when it tabled a wish list of terms for the agreement. The Manning government had been very supportive of the project in public, but until that point this had not been translated into concrete terms and there had been remarkably little discussion between project team and government during the formative stages of the project. The timing proved to be unfortunate as there was almost immediately a change in government. Premier Patrick Manning called an early election in November 1995 and both his ruling People's National Movement (PNM) and the United National Congress (UNC) won 17 seats, the remaining two going to the National Alliance for Reconstruction (NAR). Within three days of the election, the UNC formed a government under premier Basadeo Panday in alliance with the NAR. Panday, the first Trinidadian prime minister of Indian descent, was also wedded to free market policies but had not actively supported the LNG project prior to his election, and was determined to examine it critically.

As in the case of most LNG projects, the economics of Atlantic LNG were expected to be marginal when the project was in the planning stages. The cost of liquefaction and shipping are substantial and the LNG was to be exported to countries where there was competition from pipeline gas. The sponsors therefore sought some taxation relief as well as more general assurances from government. In principle, the government was supportive of Atlantic LNG. Furthermore, it had considerable experience encouraging capital-intensive industries to invest in Trinidad. As a result it had developed what amounted to a virtually standard package of fiscal incentives available through the fiscal incentives act.[20]

The elements of this package are:

- Standard tax holiday 5 – 10 years
- Relief from taxes on dividends and other distribution
- Value added tax exemptions on imports, including capital imports
- Concessions on import duties
- Relief on withholding tax

Because Atlantic LNG was seen as a pioneer industry (the first grassroots LNG plant in the Western Hemisphere for three decades) and with LNG prices expected to be low, it was granted a 10-year tax holiday.

Naturally, the project also needed a wide range of permits from government, many of which were individually negotiated rather than part of the overall government agreement. There was significant government interest in using local content and employment. LNG plants and indeed offshore gas developments are not major generators of employment when they are operating, although there are a substantial number of people involved in construction.[21]

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[20] Jobity R, Racha S, 1999 "The Atlantic LNG Project The State of Play" Economic Bulletin Central Bank of Trinidad and Tobago.

[21] In this case, 140 permanent jobs were created and of these 120 were citizens of Trinidad and Tobago (1999 figures), and the peak workforce during construction was about 3000. Projects are normally more than willing to maximise local content provided it is competitive. Most local content assurances take the form of preference to local contractors when they offer competitive terms. Very often, however, local contractors will be at a disadvantage in terms of scale, experience and credit-worthiness than their international competitors. Quite often these problems can be overcome by judicious joint venturing. As a result genuinely local content can be quite hard to define very precisely but is estimated at US$150 million for Atlantic Train 1.

A distinctive feature of the Trinidad project was that the government wanted the project to be located on a run-down site in the Brighton, La Brea area in the southwest of the island, which it wanted to see develop as a new industrial area. Unfortunately, the area was cluttered with old well sites and was essentially on the tar pitch lake that occupies a large area of the southwest of the island. Although extensive soil surveys were carried out, the sponsors could not find satisfactory foundation conditions on the unstable tar. After lengthy discussion, it was agreed that the site should be relocated 5 miles away at Point Fortin on a site owned by state oil company Petrotrin, which had the added advantage of better marine conditions but also had significant clean up problems. This decision was not finally taken until December 1995, but this change had minimal impact on overall timing, the critical path at that stage being financing.

The government agreement only came after a long and tough negotiation, and this was followed by a further negotiation between Amoco and the government to get permission for the upstream development and to gain assistance to secure a pipeline right of way across Trinidad to the LNG plant. In return, the government negotiated a reduction in island gas supply prices (a further reduction was obtained at the start of Trains 2 and 3). The project loaded its first cargo into Cabot's Mathew in April 1999, 6 months ahead of NLNG, its closest rival.

ATLANTIC TRAINS 2 AND 3

Atlantic did not move forward into expansion quite so easily, but Amoco was keen to see expansion and it was an open secret that the next trains would be the first of many expansion projects. During the course of appraisal of its reserves Amoco had found gas well in excess of that needed for Train 1 and was therefore anxious to expand Atlantic LNG as soon as possible. BG also wanted to use its reserves. Proven reserves had reached 21.3 tcf by January 2000 in strong contrast to the situation in 1994. Internal discussion of an expansion started in 1997, but serious discussions with government over terms only started in June 1999 and the final approval to proceed was only given in March 2000; the EPC contract was not awarded to Bechtel until August 2000 (although early construction had started in March). The reasons for the extended time taken to bring the development forward were mainly structural, though partly due to negotiations with the government on revised terms.

Originally the project thought in terms of a single train expansion of similar capacity to Train 1, but as the market developed this was rapidly increased to two trains and a two-train expansion was flagged in mid-1998.

Marketing and Shipping

By 1997 the market picture looked very different from 1993 and in many ways easier. There was some sign of an upward trend in U.S. prices (Henry Hub price averaged US$2.53/mmbtu in 1997)[22], which encouraged the hope that the famous U.S. "gas

[22] BP "Statistical Review of World Energy". www.bp.com.

bubble" of oversupply that had lasted for a decade had finally cleared. Events since have borne out the optimism.

There also appeared to be something of a window of opportunity to capture growth in the European market, as Nigeria LNG had run into more problems and Algeria was pre-occupied with refurbishing its existing LNG plants. At this time Trinidad had the field largely to itself in the emerging Atlantic Basin markets.

The European market was also changing. The EU was determined to promote competition in gas and electricity markets and was pushing through moves towards liberalisation first in electricity and then in gas. The UK had already (independently) taken this path, but many continental European countries were much less enthusiastic. The Spanish government, however, was one of the leaders in trying to open up its market to competition. Amoco was taken over by BP in August 1998 (the deal was finally closed at the end of the year) and although Amoco and Repsol made the first moves, both positioning themselves to operate in a liberalized Spanish market, BP also had a strong strategic interest in developing its position in the Spanish gas market.

BP saw the liberalising market as an opportunity to escape from its dependency for European sales on the state gas utilities (Enagas/Gas Natural in Spain's case) which had monopoly purchasing rights. BP was prepared to move further down the gas value chain and sell to large customers and power generators directly.

Repsol, as the major shareholder in Enagas and marketer Gas Natural saw its position as under threat. Its main reactions were to diversify internationally (hence its initial interest in becoming part of the Trinidad project) but also to develop sales for gas-fired power. Liberalization of the electricity market in Spain was clearly going to favor gas-fired combined cycle generation for virtually all market growth; this in a country virtually devoid of gas-fired power before. This promised even more rapid growth in gas demand. The flip side of the coin was that a power pool into which the generators would bid to sell power was being introduced. There was considerable uncertainty as to how the pool would perform and at what level prices would settle. This meant that the generators could not be sure of passing on their fuel costs. Buying gas on the traditional basis with long-term prices indexed largely to oil products started to look very risky.

BP needed access to LNG terminal capacity if it was to sell gas directly in the market but regulated open access to the existing terminals, although offered in theory, was still some way off in practice.

The outcome was that BP and Repsol formed a joint venture to develop a new LNG terminal at Bilbao and an associated gas fired power plant that would require about 800,000 tpa of LNG. Agreement (in principle) between BP and Repsol was reached in July 1998 and the EU gave its approval in September. Repsol committed, in principle, to take about 4 mtpa from the Trinidad expansion. This effectively underpinned the work to develop the expansion. Repsol intended to place the rest of the gas elsewhere in Spain. Gas Natural eventually took 0.64 mtpa and the Basque local distribution company based close to Bilbao, Gas de Euskadi, agreed to buy 700,000 tpa (1 bcm/year) and Repsol retained the rest for its own use.

The Bilbao terminal was structured to provide terminal and regasification services only and did not get involved in buying LNG. This was very much breaking new ground and it was late in 1999 before arrangements were finalized and contracts completed; but, thanks to the Repsol commitment, this had no real impact on the project's critical path. Although BG had earlier obtained an understanding that it would have the right to supply 50% of the gas to Train 2, it took time proving up sufficient reserves. It then targeted the improving U.S. market and finally concluded a sale to El Paso for its 2.5 mtpa, which depended on re-opening the Elba Island terminal late in 1999.

To complete the Train 2 and 3 sales after it had secured the development of Train 1, Cabot sold 0.2 mtpa of its Train 1 purchases to a new terminal and power plant in Puerto Rico. It replaced this with a purchase on 0.2 mtpa from Train 2. The Puerto Rico story is instructive in itself as it demonstrates how the flexibility offered by the U.S. market can allow the development of new satellite LNG markets in a way that would have been very difficult for traditional LNG, where the buyers were totally dependent on their LNG and could not easily release volumes in this way. BP picked up this baton in an even more innovative fashion when it sold 0.75 mtpa to the Dominican Republic without indicating any source for the gas but clearly intending to use primarily Trinidad LNG.

Amoco, which began the Train 2 and 3 development, again demonstrated its reluctance to become involved in LNG shipping by selling all its entitlement f.o.b., although BP has subsequently ordered ships and has used them to lift cargoes from Trinidad.

Clearly, a single train expansion could have been launched earlier if Amoco and Repsol could have moved alone, but they were not free to do so. With a traditional LNG project—and even for Trinidad—the delay could have risked losing market opportunities to competitors. The more flexible liberalized market in the U.S. does, however, allow volume to be placed in it at any time although there is, as always, a price risk. Even in the early stages of European liberalization, BP and Repsol had more control over their own destiny than they would have had with a traditional sale to a utility and as a result the delay had less impact than it could have.

Project Structure

The real difficulties in expanding Atlantic LNG had to do with the project's structure and the conflicting interests of the partners. The Amoco and Repsol announcement that they were planning an expansion based on the Spanish market took the other shareholders by surprise and exposed the real divergences between them. For both Amoco and BG, the primary drive behind investing in LNG was to develop gas discoveries, but BG had not yet proven the reserves it needed to fill half Train 2 and which it had gained a right to supply half Train 2 as part of its acceptance of 100% Amoco supply to Train 1. Repsol was partly driven by gaining access to reserves but was also interested in protecting itself from the threat to its Spanish market (outlined above). Cabot had no urgent need for more supply in its core market, and both Cabot and NGC relied on borrowing to fund Train 1, which was not yet on stream. Both of the smaller companies had no direct interest in gas supply and hence their main concern for an expansion would be to maximize the profit taken in then LNG plant. This promised to make the negotiation of the feed gas price very difficult. Clearly BG, Cabot and NGC saw little urgency, and without agreement of these three it would not be possible for the Atlantic company to invest in another train.

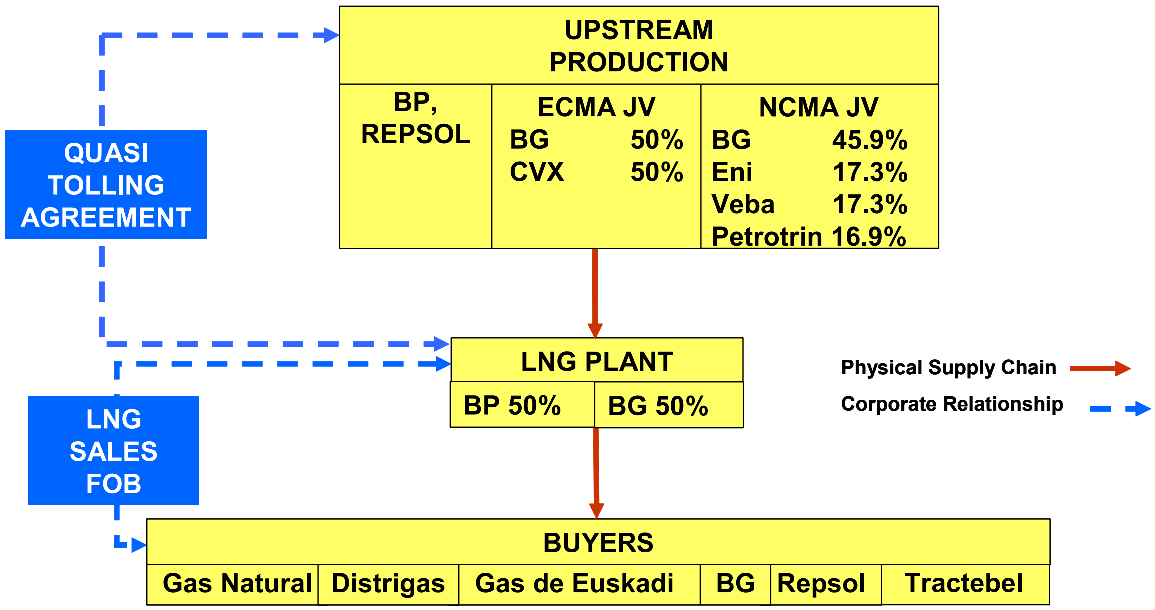
It appeared that a restructuring of the ownership of Trains 2 and 3 would be needed. Both BG and Amoco wanted to find an easier and quicker way of deciding which company should supply gas to the plant and under what terms. Very few LNG plants in the world have supplies from more than one field or license area and therefore there were few precedents. One plant of some relevance was the Bontang plant in Indonesia (which has been referred to already). That plant was owned by the Indonesian national oil company, Pertamina, and operated as a cost center. It was supplied by two main license blocks on the basis of reserves proven and not used by previous sales packages. Pertamina made all sales with the support of its gas suppliers. Sales could only be made when the big utility buyers required new supply; there was none of the market flexibility in Asia that was emerging in the Atlantic Basin.

This was not an entirely appropriate model for private sector investment nor was it tailored to the emerging circumstances in the Atlantic Basin market. The Trinidad plant would have to earn an acceptable return or no one would invest in it. Nor was there a state oil company to drive the reserves race and to impose the selection criteria. Also BP, BG and to a degree Repsol had ambitions to create their own presence in the marketplace and optimize their own portfolios of supply rather than necessarily continuing the rigid project based on links from supplier to market that were characteristic of the traditional LNG trade.

Thus, the producers were attracted to a tolling structure. The LNG plant would serve to process gas owned by the upstream gas suppliers, converting it into LNG for a defined fee. The plant owners' risk would be minimal as the suppliers would guarantee a level of throughput and would shelter the plant from any LNG price risk and the fee would be set accordingly. The upstream owners would then sell the LNG individually. The risk of destructive head-on competition between the sellers was much reduced in liquid gas markets; such an arrangement would still be very difficult to manage in Asia.

There was little in this to appeal to Cabot and NGC for Trains 2 and 3, but BP and BG needed their support to proceed. Eventually they both agreed to withdraw from investing in Trains 2 and 3 in exchange for some financial compensation. It was still not possible to have a pure tolling arrangement as the sales plans did not exactly match the ownership of upstream gas – Repsol had only gained a small foothold in gas supply when it joined the consortium and Cabot did buy some Train 2 LNG. As a result Atlantic 2/3 Company of Trinidad and Tobago Unlimited—whose shareholders are BP (42.5%), BG (32.5%) and Repsol (25%)—which was set up to own the plant, did take ownership of the gas and become the f.o.b. seller. Nevertheless, the plant was paid a fixed fee as if it were a pure tolling entity and the commercial outcome is almost identical to a tolling arrangement. This solution was not achieved easily and the negotiation spread over 1998 and 1999 and into 2000 before it was resolved.

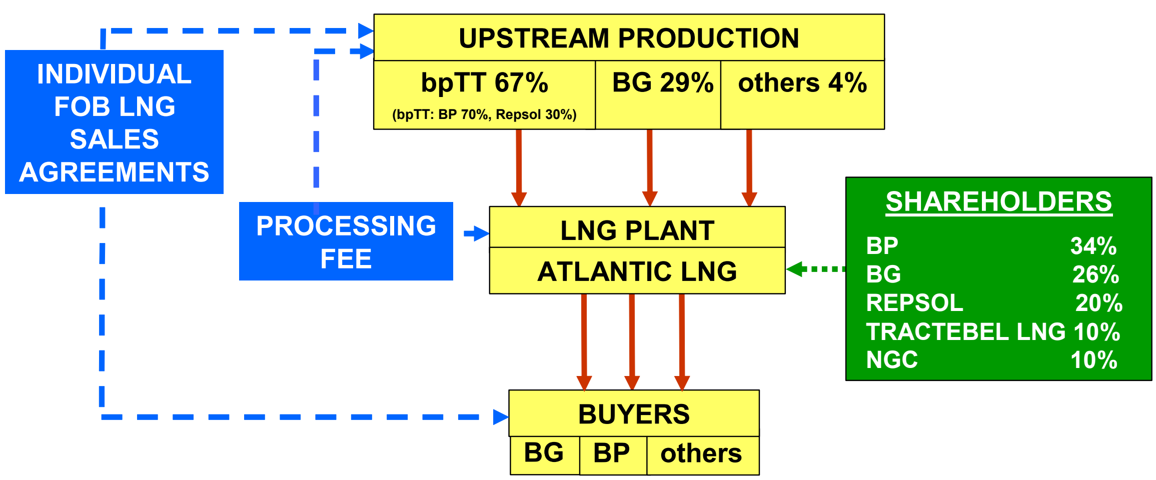
Figure 15: Atlantic Trains 2 and 3



Source: Gas Strategies

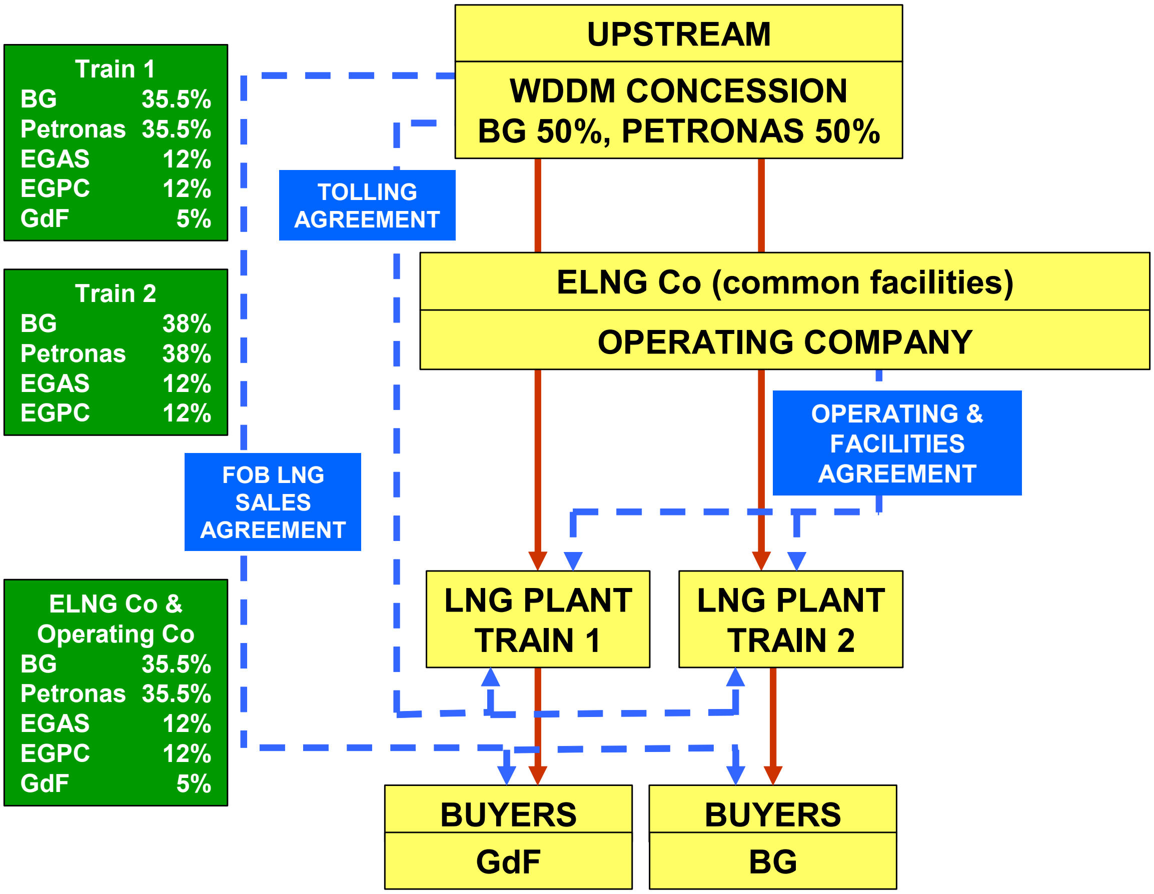
A pure tolling arrangement was finally adopted for Train 4 (Figure 16) which we do not cover in this paper. However, as Figure 17 shows, even before the Train 4 structure was concluded, BG had launched in Egypt LNG what we think deserves to be seen as a sort of "Trinidad graduation project." This was not only a tolling structure, but can be easily expanded a train at a time, with new investors in separate trains and new producers if need be. The figure shows it after a Train 2 addition has been added to the original Train 1 structure.

Figure 16: Train 4 Structure



Source: Gas Strategies

Figure 17: Egypt LNG Structure



Source: Gas Strategies

Government Agreement

In spite of the hard fought terms agreed for Train 1, there was still significant press criticism of the terms granted to Atlantic LNG. By this stage it was apparent that prices in the US were higher and the economics of Train 1 likely to be better than expected. Trains 2 and 3 would in addition benefit from economies of scale, sharing common facilities such as the jetty and storage. The project did not seek a tax holiday for the plant in this case. In February 2000 the Sustainable Economic Development Unit of the University of the West Indies Economics Department organised a symposium to attempt to influence terms for Trains 2 and 3 and the principle organiser of the forum, leading academic Dennis Pantin, raised concerns in the press. Although it was variously claimed that the project would provide US$30 - US$48 billion in tax revenue over its 20 year life, Pantin argued that there would be an opportunity loss of US$3.3 – US$5 billion because Atlantic would not be paying a fair market price for the gas.[23] Heads of agreement between the project and government were signed in March 2000 but before the deal was finalised. BP and BG agreed to reduce prices for gas supplied to NGC for sale in the island (reportedly from US$1.03/mmbtu to US$0.91/mmbtu[24]).

Local content was expected to be 25% and again there would be about 3,000 construction jobs at peak.

ANALYSIS OF ALTERNATIVE PROJECTS

Nigeria LNG

The most active direct competitor to Atlantic LNG is undoubtedly Nigeria LNG. LNG in Nigeria has a very checkered history. Nigeria has massive reserves of gas (3.4 tcm), much (but by no means all) of it associated with oil. Relatively little gas was used in Nigeria and much of the associated gas was flared, which was both wasteful and environmentally damaging. Use of this gas and elimination of flaring is of real strategic importance for the country.

An LNG development was first proposed in 1964 in the very early days of the LNG industry and this was picked up in 1969 when market studies of the US, Brazil and Argentina were carried out. As a result, attempts were made to develop two separate three-train projects. One was to be developed by BP and Shell at Bonny and the other by Elf, Agip and Phillips at Peterside on the other side of the Bonny River. The government was to be a major partner in both. Things moved fairly slowly (the Biafran civil war only ended in 1970 and LNG was a very new and expensive technology) and in 1977 the government decided that the two projects should be merged to develop a six-train plant at Bonny. This plan was completed in 1978 when the sponsors signed a shareholders agreement and the government issued a Letter of Guarantee and Assurance. Shareholdings at that point were NNPC 60%, Shell 10%, BP 10%, Agip 7.8%, Phillips 7.5% and Elf 5%. The plan was to produce 12 mtpa of LNG. By this time marketing was focused on the US (Columbia LNG, Southern LNG, Trunkline LNG and American Natural LNG) and Europe (Consortium of 8 buyers). Sales agreements were negotiated and initialled but the combination of the market collapse in the early 1980s already referred to and a change in government in Nigeria effectively stopped the project. BP and Phillips failed to renew the shareholders agreement in early 1982 and left; the company was liquidated.

In April 1982 the new government commissioned consultants to carry out an LNG feasibility study, and they concluded that Nigeria would be well placed to capture the LNG market in Europe. Shell, Elf and Agip were invited to participate in a new project and had

[23] Reported in Gas Briefing International 28.3.2000. London.
[24] Ibid.

all expressed interest by November 1983, but again the government changed that December. The new military government set up a task force to review previous LNG efforts and to make recommendations. The task force reported in March 1984 and an LNG working committee was established in March 1985. This was followed by the signature of a framework agreement in November 1985 by NNPC, Shell, Cleag (Elf), and Agip. Shell was made technical adviser and eventually the joint venture was incorporated in 1989 as Nigeria LNG Ltd. (NLNG). Shareholdings at that stage were NNPC 60%, Shell 20%, Agip 10% and Elf 10%.

From this point the project moved steadily forward; the French Tealarc liquefaction process was chosen (and accepted rather reluctantly by technical adviser Shell). The scale was reduced to 4 mtpa (5.7 bcm/year). FEED was completed and the main EPC contract bids invited in October 1991. Bids were due in by May 1992 and award was expected in September 1992. Sales contracts were negotiated and agreed with Enagas (1 bcm/year), Gaz de France (0.5 bcm/year), and ENEL, the main Italian power company (3.5 bcm/year), all on a CIF basis. Cabot also negotiated a deal for 0.7 bcm/year on f.o.b. terms. Cabot had a distinctly uneasy relationship with the Nigerian project as it had long disputed the ownership of one of the second-hand ships, the *Gamma*, formerly owned by MarAd. Cabot eventually arrived at an agreement to use the ship to carry its own volume but with the spare capacity leased to NLNG. There was none of the flexibility in destination that Cabot eventually negotiated in Trinidad; the full volume had to go to Boston.

The project had presciently acquired four second-hand LNG carriers in 1990 and was well on the way to amortising their cost by chartering them to LNG suppliers in the Pacific. It intended to raise limited recourse financing and engaged the IFC to carry out an appraisal study by May 1992. It was in this period that Cabot, clearly doubtful about the chances of the Nigerian project proceeding, approached the Trinidad and Tobago government.

And indeed, it was not to be. The government refused to support the award of the EPC contract and, for good measure, what it saw as Shell's choice of liquefaction process. At the same time it sacked the entire board of NLNG.

The project was re-launched in December 1993 following substantial restructuring. Limited recourse financing was not a realistic prospect in Nigeria at the time. The IFC suggested that IFC participation in the project could help its credibility with the financial community but this would require a reduction of the NNPC share below 50% as the IFC could only help projects that were majority privately owned. The NNPC share was to be reduced to 49%, Shell's increased to 24%, Elf's to 15% and Agip's remained at 10%. The IFC was offered 2%. Rather neatly for Nigerian sensibilities there was no majority of foreign shareholders in spite of NNPC having lost its overall majority. A new shareholders agreement was in place at the time of the re-launch. The Tealarc process had been abandoned in favour of the almost universal APCI and capacity was to be increased to 5.2 mtpa (7.15 bcm/year) but this meant a redesign. A new go-ahead date in the first quarter of 1995 was set with start up scheduled in 1999. To try to assist the funding problem and to try to improve credibility with the financial institutions an escrow account was set up and each partner was required to subscribe a significant proportion of its equity up front. However, the advent of the IFC made little difference and no real progress was made with external financing.

Later in the 1995 the IFC pulled out, alarmed over the human rights situation in Nigeria (Ken Saro-Wiwa and eight other dissidents were executed in November). The final shareholdings settled at NNPC 49%, Shell 25.6%, Elf 15% and Agip 10.4%.
The project tried as far as possible to hang on to the sales that it had agreed. ENEL and Gaz de France were retained and Enagas actually increased its commitment to 1.6 bcm/year. For the time being Cabot was still committed to take 0.7 bcm/year. However, ENEL could not commit irrevocably until the Italian government decided to give its approval to build the new receiving terminal at Montalto di Castro that was essential if it was to be able to take the LNG, and the Italian government appeared to be in no hurry to decide.

In December 1994 NLNG had signed a memorandum of understanding with its preferred construction contractor. By March 1995, with the Italians still undecided and no financing, NLNG was in some danger of losing both its sales and its plant construction contract. It managed to roll over the engineering contract but the sales were not so simple this time; buyers' patience was running out. Gaz de France agreed to extend the deadline to about November 1995 as did ENEL, but ENEL not surprisingly dropped its option to take an extra 1.1 Bcm/year. Botas of Turkey, where demand was also predicted to grow very rapidly over the next few years, was lined up for 1.2 bcm/year to replace the lost ENEL quantity. Cabot cannily suspended but did not cancel its contract, allowing it to wait and decide when the others were ready. ENEL was given a deadline of 31 May to go firm. The Italian government did not decide. NLNG said that it required hearing what ENEL's decision was by the end of June and ENEL, under pressure, went firm. This was to come back to haunt it later when approval for the terminal was refused as was the back up terminal proposed by SNAM at Monfalcone.

Cabot, now confident of Trinidad and wanting to gain full control of the ship the *Gamma,* cancelled its contract in November.

All was not quite done; the final investment decision was postponed from September to November, when the board failed to decide, and was finally made in December. There was no financing. The Escrow account contained nearly half the total funds required and the project proceeded n the basis of equity financing. In spite of taking the final investment decision seven months ahead of Atlantic LNG, NLNG did not deliver its first cargo until October 1999 six months behind Atlantic.

Undoubtedly, in 1992 the Nigerian project was well ahead of Atlantic and had almost secured the important US niche market. It is equally clear that most of its problems were inflicted by the government. The government, by its lack of consistency and poor communication with its own national oil and gas company, has contributed strongly to the failure of several incarnations of the project. Changes of government for many years were followed by total re-appraisal of the project and more delay. Unrealistic ambitions for project finance contributed to the delays. However, in the later stages the drive of the management, by then Shell led, managed to overcome several quite serious obstacles and finally did see the project proceed. It was still just in front of Trinidad, but it had allowed Trinidad to take over the Boston market (more critical for Trinidad than Nigeria) and capture a slice of the Spanish market that might otherwise have gone to Nigeria.

When it came to expansion, however, Nigeria did not have the structural problems of Atlantic Trains and 2 and 3. Some characteristically Nigerian problems continued to dog it through 1997. In June, the energy minister, Dan Etete, announced that he had "sacked" the whole board of NLNG. He had failed to take account of the fact that NNPC now owned only 49% of the company and that he was not in a position to sack the whole board, which, fortunately, managed to survive and continue to develop the project. The situation in Italy had not improved, however. ENEL ran into environmental difficulties with its proposed receiving terminal at Montalto di Castro north of Rome and switched to its fallback option, SNAM's proposed terminal at Monfalcone. Following the cancellation of this terminal after a local referendum in September 1996, ENEL attempted to cancel its contract with NLNG. NLNG took the matter to arbitration and by March 1997 ENEL had promised to honour the contract. ENEL then had to make arrangements with Gaz de France (GdF) for most of the LNG to be taken into GdF's terminal at Montoir and then swapped for a combination of pipeline gas from Russia and Algerian LNG (the latter delivered to the one existing Italian LNG terminal at La Spezia). These were completed by the end of 1997 leaving NLNG free to contemplate a third train expansion in 1998.

By February 1999 it had signed up Enagas to buy 2 mtpa, 70% of the output of Train 3 and had committed to the TSKJ consortium to build the train as a carbon copy of Trains 1 and 2, and in June 1999 Transgas of Portugal bought the remaining 0.7 mtpa output. The third train started up at the end of November 2002. Again this was three months later than Trinidad Train 2, although the Nigerian investment decision was taken 15 months earlier. Nevertheless Nigeria moved forward to expand far quicker than Atlantic. It had avoided Atlantic's structural difficulties; Train 3 for NLNG was simply more of the same. In this case there was enough market to take both expansions, Spain's rapid market growth being a key factor, although the more conservative Nigerian project sold to the traditional buyer and was not so concerned to position itself for the changing European market structure.

Venezuela

The other LNG project that had the potential to thwart Atlantic's ambitions was in Venezuela, a mere stone's throw from Trinidad. The genesis of the Venezuelan Cristobal

Colon LNG project was a study conducted by Shell and Lagoven (a subsidiary of the national oil company PDVSA) in 1989 that identified potential commercial opportunities for LNG (although Venezuela had also toyed with the idea of an LNG project in the early days of LNG some 20 years earlier). Venezuela had nationalised its oil and gas industry in 1975, later than most OPEC countries. By 1990 it was sitting on resources (proven, probable and possible) of 6.6 tcm of gas of which 0.9 tcm was non-associated, which it wanted to exploit. It was realised that foreign participation would be necessary to progress a project but foreign participation was not permitted under the nationalisation legislation. It was also very much a political hot potato with strong opposition in some quarters within the country to the re-introduction of foreign oil companies. However the government was, in principle, prepared to reward foreign companies prepared to invest in less desirable heavy crudes with access to other hydrocarbons. Lagoven set out to select suitable joint ventures and in June 1990 Shell, Exxon and Mitsubishi were invited to take shares of 30%, 29% and 8% respectively. Congressional approval would be needed to permit the setting up of the joint venture company, which was otherwise prohibited under Article Five of the Oil Nationalisation Law. The initial feasibility study proposed a two train 4.6 mtpa plant using 7.5 bcm/a of feed gas. The target market was the USA and three 127,000 m^3 ships would be required.

The new joint venturers were given access to some rather unpromising reserves offshore the Paria peninsula in the east of the country. This appears to have been in part at least a concession to the opposition to letting foreign companies back in; they were given difficult reserves in a relatively under developed part of the country to provide reassurance that foreign companies would not be permitted to act against the national interest. These were very close to and essentially of similar character to the Trinidad North Coast reserves which Atlantic was to reject for Train 1 because they lacked associated liquids and were too costly to develop. The next three years were spent trying to prove up more reserves and to come up with a development scheme that had some realistic chance of being economic. They were somewhat enlivened by a well publicised dispute between Shell and Exxon over the degree of access to Shell's technical LNG know how; some US$30 million were spent over the three years. The scale was increased to 6 mtpa in an effort to achieve economies. An accord was signed between the companies in March 1993 and congressional approval was sought. The project was approved in August after long debate in Congress and the company (Sucre Gas) formed early in 1994. However, the project never managed to find a convincingly economic development and the projected final approval in 1996 followed by construction start in 1997 never materialised; the project faded away. It was burdened with low quality gas, partly for political reasons. It did not have access to the low cost second-hand ships that Trinidad and Nigeria had. Marketing never made real headway. The prime focus was always on the U.S. and the project struggled with the low price expectations. The rather high priced niche at Boston would have been useful but would inevitably have been a small proportion of a 6 mtpa project. It was reported that the project was seeking prices of the order of US$4.0/mmbtu in 1993[25] (when Nymex gas price averaged US$2.12/mmbtu), which gives some insight as to what was needed to make it viable. European sales were not considered until much later.

[25] Ibid 28.8.1994.

CONCLUSIONS

A number of factors contributed to the success of Atlantic Train 1 compared to its competitors in Nigeria and Venezuela.

The first was the combination of small scale, low cost, and capturing the vital U.S. niche market. These three factors are interrelated and a product of the vision of the project developers. The Boston market was captured by a combination of Cabot's direct involvement, plus a more flexible deal than the one already negotiated by Cabot with Nigeria, plus the difficulties the Nigerian project continually ran into. This all-important high-priced Boston market was quite small, and as a result it would only form a small portion of sales from the larger Nigerian and Venezuelan projects. This meant that these projects needed to find much larger additional sales that would take time to arrange, if they could be arranged at all, and which would inevitably be at lower prices. However, a small-scale project was likely to lose economies of scale, so cost reduction was very important for Atlantic, particularly as the economics for all projects in the Atlantic were quite marginal.

A significant contributory factor to the success of Trinidad but also of Nigeria was Spain's desire to diversify gas supply away from almost total dependence on Algeria. Spain does have a small contract with Norway, which predates Trinidad and Nigeria but the gas, which has to transit the whole of Europe is very expensive and LNG provided a far more attractive option. The Spanish government is trying to keep the proportion of Algerian gas below 60% and Qatar is also now a regular supplier.

The other major factor was far more consistent government support (in spite of some noise and hard negotiation) and encouragement in contrast to Nigeria, which suffered from what must have appeared to be random and unhelpful government intervention and from a government in Venezuela that had to struggle to gain internal acceptance of foreign involvement in the project. The compromises it had to make to get the principle accepted fatally weakened the chances of the project proceeding.

Some determined management action did pull the Nigerian project out of the fire at last but Trinidad by then had found its place.