LNG Boom: Middle East and Africa

New LNG trade, issues and impacts

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Global LNG Boom

The worldwide natural gas market, LNG in particular, is booming, as manifested by the jump in LNG trade and increase in LNG liquefaction capacity, regasification capacity, and the number of LNG vessels on order. Global natural gas consumption increased by 3% in 2003 while global LNG demand surged by 11% in the same period. Total worldwide LNG production stood at 125 million tonnes in 2003 as illustrated in Table 1. The Middle East and Africa region produced 46% of the world's LNG, almost at par with Asia Pacific in terms of production. Qatar has become the fourth largest LNG exporter in the world, and has firm plans to become No. 1. Although Asia Pacific remains the largest LNG importing region, the U.S. and Europe are the fast growing LNG markets.

Table 1: LNG Exporters and Importers in 2003

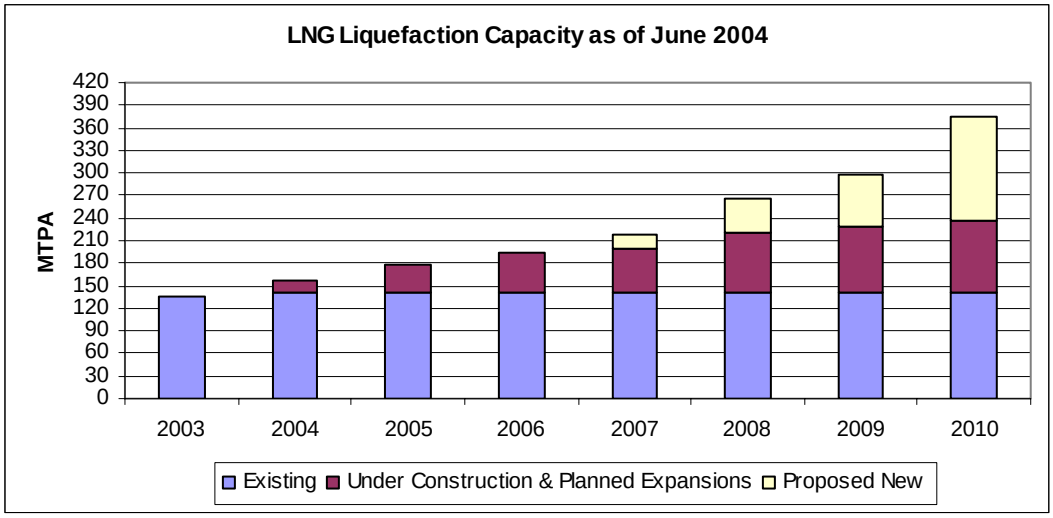
Exporters	Capacity (MTPA)*	Millions Tonnes	% of Total	Importers	Millions Tonnes	% of Total
Middle East and Africa	***63.0***	***56.9***	***45.5***	***Asia Pacific***	***83.5***	***66.7***
Qatar	19.6	14.3		Japan	58.5	
Oman	7.3	6.8		S. Korea	19.4	
Abu Dhabi	5.7	5.3		Taiwan	5.6	
Algeria	20.3	21.3		***Europe***	***30.4***	***24.3***
Nigeria	9.5	8.7		Spain	12.1	
Libya	0.6	0.6		France	9.2	
Asia Pacific	***66.3***	***58.1***	***46.4***	Belgium	2.5	
Indonesia	29.4	26.5		Italy	2.5	
Malaysia	22.2	16.8		Greece	0.4	
Australia	7.5	7.6		Portugal	0.2	
Brunei	7.2	7.1		Turkey	3.5	
Westerb Hemisphere	***11.3***	***10.1***	***8.1***	***The U.S.***	***11.0***	***8.8***
Trinidad and Tobago	9.9	8.8		***Others***	***0.2***	***0.2***
US	1.4	1.3		Dominican Rep.	0.2	
Total	**140.6**	**125.2**	100.0		**125.2**	100.0

Source: EIA, and Oil and Gas Journal, June 14, 2004
** As of June 2004*

On the supply side, as of June 2004, there are 15 LNG liquefaction sites located in 12 countries with 68 trains and an aggregate capacity of approximately 140 million tonnes per annum (MTPA), of which 63 MTPA is from the Middle East and Africa[1]. The worldwide aggregate capacity under construction & planned expansion is approximately 100 MTPA as of June 2004. In addition, there are more than 20 proposed new liquefaction projects worldwide with a production capacity of approximately 140 MTPA. As shown in Chart 1, total worldwide existing capacity and the capacity under construction & planned

expansions will approach approximately 240 MPTA by 2010. If all the proposed new LNG liquefaction projects are constructed by 2010, the aggregate worldwide liquefaction capacity could reach approximately 380 MTPA by then.

Chart 1: Worldwide LNG Liquefaction Capacity as of June 2004



Source: EIA. Bar height shows the cumulative year end liquefaction capacity available.

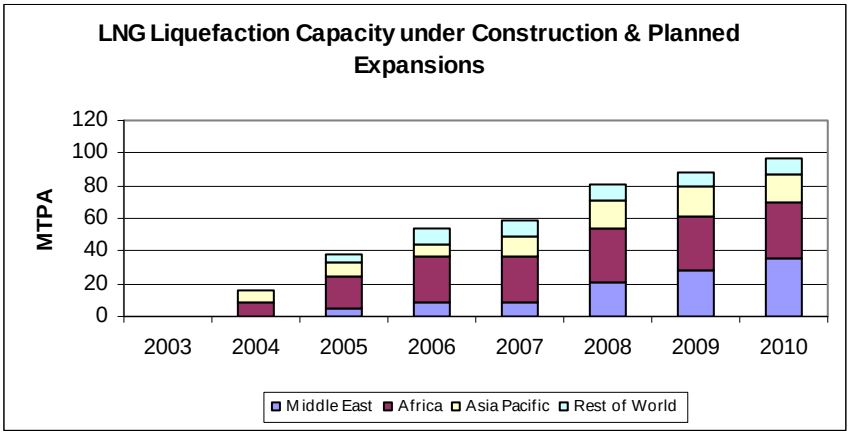
On the demand side, worldwide gas and LNG consumptions are forecasted to increase by 3% and 10% per annum, respectively, from the present to 2008, exceeding the 2% annual growth rate for worldwide oil consumption[2]. Over the longer term, it is predicted that worldwide LNG consumption could reach 185-218 million tonnes by the end of 2010, and 286-350 million tonnes by 2020[3]. It is also predicted that gas will take over oil as the fuel of choice between 2020 and 2030[4].

Surging LNG Supply Capacity in the Middle East and Africa

The Middle East and Africa will continue to pay a major role in supplying LNG to the world markets. Supply from this region accounted for approximately 46% of total LNG consumption in 2003. This region is also home to more than 50% of the worldwide LNG liquefaction capacity currently under construction & planned expansions (Chart 2).

The Middle East traditionally supplies customers in Asia, but the projects under construction and planned expansions and proposed new projects in this region will target the U.S. and European markets, which are fast growing with the largest growth potential. 60% of the new liquefaction capacity will originate from the Middle East and Africa.

Chart 2: LNG Liquefaction Capacity under Construction & Planned Expansions
(As of June 2004)



Source: EIA. Bar height shows the cumulative year end liquefaction capacity available.

Table 2: Middle East and Africa: Projects under Construction and Planned Expansions as of June 2004

Country	Project	Status	Plant Capacity MTPA	Sponsors	Start-Up Date	Offtakers
Algeria	Skikda	replacement	4.0	Sonatrach		Europe
Nigeria	NLNG T4 & 5	under construction	8.2	NNPC, Shell, Total, AGIP	2005	Transgas, Shell, ENI, Ibedrola
	NLNG T6	planned expansion	4.1	NNPC, Shell, Total, AGIP	2007+?	US / Europe?
	Total Nigeria		**12.3**			
Egypt	Damietta T1	under construction	5.0	Union Fenosa, EGPC	2004	Spain
	Idku T1	under construction	3.6	EGPC, EGAS, BG, Gaz de France, Petronas	2005	Entire output contracted to Gaz de France
	Idku T2	under construction	3.6	EGPC, EGAS, BG, Gaz de France, Petronas	2006	Targeting Europe
	Damietta T2	planned expansion	5.0	Union Fenosa, EGPC	2006+	Targeting Europe
	Total Egypt		**17.2**			
Oman	Qalhat	planned expansion	**3.3**	Oman Govt., Shell, Union Fenosa, others	2006	Union Fenosa (Spain)
Qatar	Ras Laffan T4	under construction	4.7	QP, ExxonMobil	2005	Edison Gas (Italy)-3.5, Endesa Generacion (Spain)-0.8
	Ras Laffan T5	planned expansion	4.7	QP, ExxonMobil	2008	CPC (Taiwan), Spain
	Qatargas II T1	planned expansion	7.8	QP, ExxonMobil	2008	UK market (via Sponsor affiliate)
	Qatargas II T2	planned expansion	7.8	QP, ExxonMobil	2010	UK market
	Qatargas III	planned expansion	7.8	QP, ConocoPhillips	2009	US market
	Total Qatar		**32.8**			
Total Middle East and Africa			**69.6**			

Source: EIA, Poten & Partners, and Oil and Gas Journal.

Algeria

The explosion at the Skikda plants on January 19, 2004 killed 27 people and injured 58. This accident heightens the public's fears about LNG safety. The accident destroyed three out of the six trains and cut the plant's capacity from 6 MTPA to 3.2 MTPA, a loss of 2.8 MTPA. Sonatrach plans to build a 4 MTPA train at Skikda to replace the lost trains and to meet its obligations under long term contracts.

Nigeria

The 8.2 MTPA Nigeria LNG Trains 4 and 5 are scheduled to come on stream in 2005, increasing Nigeria's LNG production capacity to 17.7 MTPA by 2006. The 6.1 MTPA Train 6 Expansion is planned for start-up in 2007 but no financial investment decision has been made.

Egypt

Egypt is set to become a new LNG exporter in 2004 with the scheduled start-up of the 5 MTPA LNG plant at Damietta, Egypt in late 2004. The 3.6 MTPA-each Train 1 and Train 2 of the LNG plant at Idku, Egypt are scheduled to start up in 2005 and 2006 respectively, raising Egypt's LNG export capacity to 12.2 MTPA by 2006. A second 5 MTPA train for the Damietta project is planned for start-up beyond 2006.

Oman

The 3.3 MTPA Train 3 expansion of Oman LNG is schedule to start up in 2006, raising Oman's export capacity to 10.6 MTPA by 2006.

Qatar

The 4.7 MTPA Ras Laffan Train 3 came on stream in March 2004. This is the largest single train liquefaction facility currently in operation. The 4.7 MTPA Ras Laffan Train 4 is scheduled for start-up in 2005, raising the total export capacity of Qatar to 24.3 MTPA by 2006. Qatar will have the second largest LNG liquefaction capacity by 2005. The Ras Laffan Train 5 with 4.7 MTPA is planned for start-up in 2008 with the FEED being issued in early 2004.

The 7.8 MTPA-each Train1 and Train 2 of Qatargas II are scheduled to start up in 2008 and 2010, respectively. Train 1 will become the largest single LNG train in the world at its scheduled start-up in 2008. The 7.8 MTPA Qatargas III is schedule for start-up in 2009, targeting the U.S. market.

By the end of 2010, the total LNG liquefaction capacity from Qatar is expected to reach 68 MTPA, making Qatar the largest LNG exporter in the world at that time.

Planned New LNG Projects in the Middle East and Africa

The major planned new LNG projects in the Middle East and Africa are listed in Table 3.

Table 3: Middle East and Africa: Planned New LNG Projects as of June 2004

Country	Project	Plant Capacity MTPA	Sponsors	Start-Up Date	Offtakers
Algeria	Arzew (new)	**4.0**	Gassi Touil Integrated Gas Project	2008+ ?	Targeting Europe?
Angola	Soyo	**8.0**	Sonangol, Chevron Texaco, BP, ExxonMobil, Total	2008+	Targeting US and Europe
Equatorial Guinea	Bioko Island	**3.4**	Marathon, GE Petrol	Late 2007	Signed MOU with BG for 3.4 MMTA with flexibility in gas destination
Nigeria	Brass LNG	**10.0**	NNPC, ENI, ConocoPhillips, Chevron Texaco	2009	Targeting US and Europe
Qatar	Ras Laffan II (T6&7)	**15.6**	ExxonMobil, Qatar Petroleum	2010	US Market
Iran	NIOC LNG	8.0	NIOC, BG, Enel, Agip		
	Iran LNG	8.0	NIOC, BP, Reliance Petroleum		
	Pars LNG	10.0	NIOC, Total, Petronas		
	Persian LNG	10.0	NIOC, Repsol, Shell		
	Total Iran	**36.0**			
Total Middle East and Africa		**77.0**			

Source: EIA

Algeria is proposing to build new 4 MTPA LNG train based on gas from the Gassi Touil field.

The 8 MTPA 2-train LNG plant at Soya, Angola is under planning for start-up beyond 2008.

The 3.4 MTPA (net) LNG plant in Equatorial Guinea sponsored by Marathon Oil Corporation and GEPetrol, the national oil company of Equatorial Guinea is scheduled to come on stream in late 2007.

The 10 MTPA Brass LNG project in Nigeria is being studied for possible start-up beyond 2007.

Ras Laffan II (Trains 6&7) with a combined capacity of 15.6 MTPA is planned to start up in 2010 for exporting to the U.S. market.

Iran may become a potential major LNG exporter in the future. Four LNG projects with a total capacity of 36 MTPA are being studied by western oil companies and NIOC.

Key Drivers of the LNG Boom

First, increasing natural gas demand in key market countries of international oil companies (IOCs) is the driving force behind the LNG boom. The tremendous increase in demand from key markets such as the U.S. and Europe and the opening of emerging markets provide the basis for LNG expansion. The U.S. is the fastest growing LNG market in the world, with an estimated LNG growth of 4 folds from now to the end of this decade[5]. Quite a number of emerging markets are poised to become LNG importers before the end of this decade. The IOCs are the major participants, and the key commercial lenders in almost all the LNG projects in the Middle East and Africa.

Table 4 lists the net LNG production capacity of IOCs and national oil companies (NOCs) in the existing projects as of June 2004.

Table 4: Net LNG Production Capacity of IOCs in Existing Projects (June 2004)

IOC or NOCs	Country	Production MTPA	IOC or NOCs	Country	Production MTPA
Sonatrach	Algeria	**20.30**	**Marubeni**	Japan	**0.62**
Qatar Petroleum	Qatar	**12.84**	**NOC**	Libya	**0.60**
NNPC	Nigeria	**4.66**	**BP**	UK	**0.57**
Shell	UK/NL	**4.62**	**Korea LNG**	S. Korea	**0.37**
ADNOC	UAE	**3.99**	**Itochu**	Japan	**0.33**
ExxonMobil	USA	**3.89**	**Kogas**	Korea	**0.33**
Govt Oman	Oman	**3.72**	**Mistubishi**	Japan	**0.20**
Total	France	**2.94**	**Japan LNG**	Japan	**0.20**
Mitsui	Japan	**1.68**	**Partex**	Portugal	**0.15**
ENI	Italy	**0.99**			
			Total Middle East and Africa		**63.00**

Source: EIA and Company websites.

Super majors such as ExxonMobil and Shell hold sizable liquefaction capacity in the Middle East and Africa. Other IOCs such as Total, ENI and BP also hold considerable liquefaction capacity, followed by Japanese trading companies and downstream LNG users such as Mitsui, Marubeni, Japan LNG, and Korea LNG.

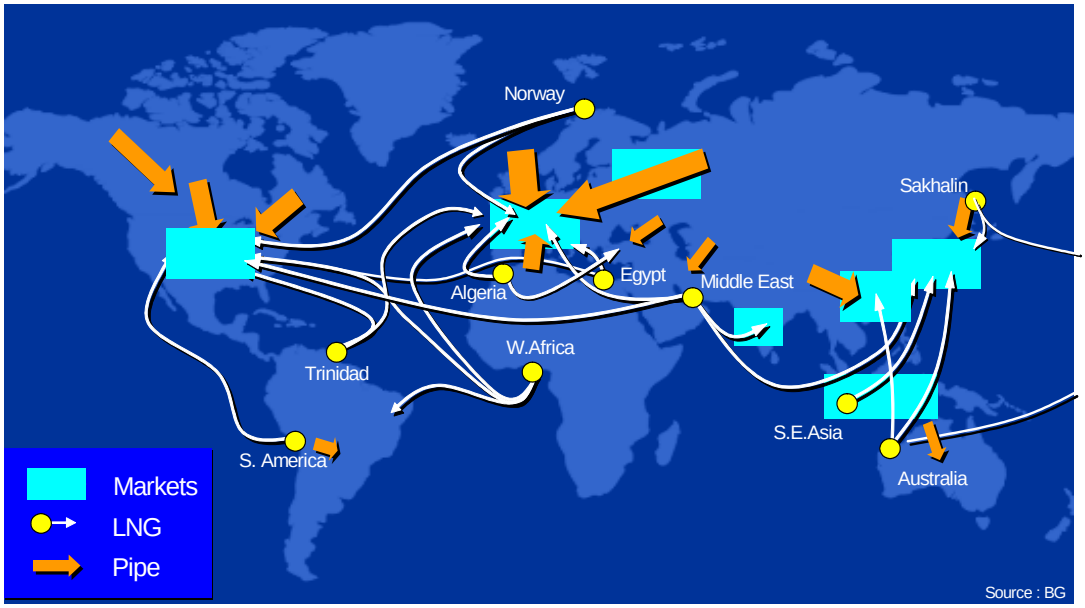
The second driver comes from technology advances, which have relentlessly driven down the cost of liquefaction. Capital cost per MTPA of capacity has come down by more than 50%, from around US$500 per MTPA of capacity in the 1970s to around US$250 per MTPA of capacity today. Larger and larger LNG liquefaction projects are being built to capture the benefits of economies of scale. At the same time, the capital costs of LNG ships have also come down. The overall cost of delivering LNG over the chain has been reduced, which has improved LNG's competitiveness against pipeline gas and other fuels.

The natural gas demand and supply situations in the U.S. and Europe indicate higher natural gas prices in the coming years, enabling LNG to readily compete with pipeline gas and other fuels.

Global LNG Market Structure

Chart 3 is a depiction of the forecasted LNG trade flow in 2010. Africa/Middle East production will serve all key gas market regions.

Chart 3: Forecast Global Gas Trades beyond 2010



Currently there are three major LNG markets and three major LNG producing regions. The three major markets are Asia Pacific, Europe and the U.S. Of the 125 million tonnes of LNG exported in 2003, 67% was consumed by Asia Pacific, 24% by Europe, and 9% by the U.S. The three major LNG producing areas are the Middle East & Africa, Asia Pacific and the Western Hemisphere. Of the total LNG production in 2003, 46% came from the Middle East and Africa, 46% from the Asia Pacific, and 8% from the Western Hemisphere (Table 1).

Largely due to high capital intensity of the LNG chain, the LNG trade today is characterized by predominantly long term gas sales and purchase agreements (GSPAs). Long term committed offtake is necessary for the upstream and liquefaction investors to make their investment decisions and to arrange financing for such high cost assets. Such long term contracts are also beneficial to the buyers who prefer price stability, predictability and security of supply. These factors that shape the current GSPAs will continue to exist beyond 2010, making long term contracts an indispensable part of the trade. However, significant new developments have occurred in the past few years which, although will not revolutionize, yet will have material impact on the ways the business is traditionally conducted.

It is predicted that the general structure of the LNG trade by 2010 will remain similar to today's market model. However, there will be new entrants of both exporters and importers, and there will be new changes in the structure of the trade. The new features in the structure of trade include more interactions between the currently fragmented or regional gas markets, and more flexibility in the long term gas sales contracts.

New Trends in LNG Trade and Market Structure

Long term contracts will continue to prevail, but with more flexibility built into those contracts. New GSPAs demonstrate the buyers' emphasis on flexibility and less concern on security and reliability of supply.

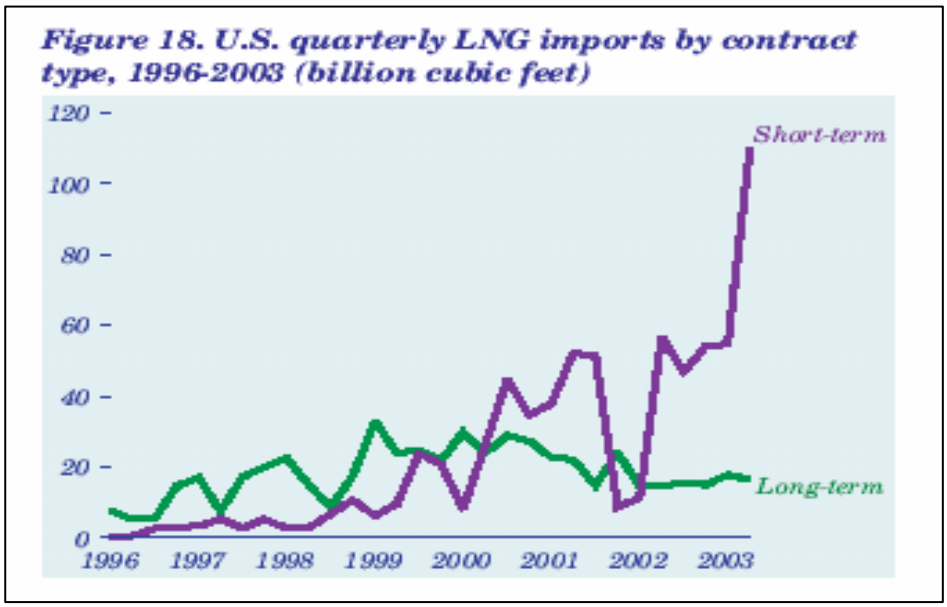
- The average contract term remains 15 to 20 years although price provisions valid for 3 to 5 years may be built into the contracts. For instance, a Japanese utility renewed an expiring contract with a price reduction, plus a two-tier sales arrangement with 25% of sales in FOB terms while the rest in D.E.S. terms.
- There is a great amount of flexibility with the take-or-pay requirements. Commitment of less than 100% of the output capacity has become acceptable to investors and lenders. For instance, the Malaysia Tiga project was built without 100% of the production capacity being committed.
- Sellers have the flexibility in marketing to several different locations compared with the traditional trade where LNG was transported in designated LNG tankers with a "destination clause" that prevented buyers from reselling the cargos to third parties. The EU is insisting that LNG sellers remove destination clauses from their contracts. Several new LNG contracts have already given buyers the flexibility to choose destinations. The Equatorial Guinea LNG project is such an example[6]. With the removal of the destination clause, control over shipping under buyer defaults has become an issue for the sellers to reckon with, as ships are no longer strictly tied to a single LNG project.
- Buyers have the flexibility in finding sources of supply, including spot cargos. Buyers will be able to conduct price arbitrage between different markets, such as the U.S. market and European market, or between the U.S. market and Asia Pacific market.
- LNG price is now breaking away from the oil-based formulas. Several new LNG projects are now indexed to either the U.S. Henry Hub or the National Balance Point price of the U.K.
- The seller is selling to "the market" instead of an AAA utility. Marketing LNG through offtaker into the gas grid is becoming the structure in the U.S. market and European market. A high volume supplier/marketer in the gas grid would have multiple options, including hedging.
- Price volatility is becoming the greatest commercial and credit risk as the seller receives a netback from the benchmark market price.
- Credit risk shifts to broad market evaluation, rather than single buyer being critical. To a certain extent, the strength of the broad market is more important than the creditworthiness of a single buyer, who also takes price risks and its credit strength is affected by general market conditions.
- Access to regasification capacity still remains crucial to both sellers and buyers of LNG. Regas access determines market access. This is why the key players such as Shell, ExxonMobil, BP, and BG are investing in regasification terminals in key markets.

There is an increasing trend for LNG buyers to participate in the upstream liquefaction plants and for reserves owners to participate down the value chain. The buyer's power is best illustrated by the Egyptian LNG project at Damietta, which is sponsored by Union Fenosa, a major Spanish energy company. For another example, Tokyo Gas invests in the Darwin LNG plant in Australia while CNOOC invests in the Australian NWS LNG project. The best example of reserves owner going downstream is the Qatargas II project, in which an ExxonMobil/Q.P company is the offtaker and is directly involved in the regasification, trading and sales of LNG in the U.K.

The new trends in the LNG trade have significant impact on new LNG projects as the GSPAs of the new project will more or less follow the new developments. New GSPAs may include slightly shorter term, 10 year contracts. Although they retain the take-or-pay features, there will be more flexibility granted to both sellers and buyers. In addition, there will be seasonal contracts and short term contracts for tradable cargos.

The changing market structure is boosting short term sales, which accounted for 10.8% of global traded LNG in 2003, compared with 8% in 2002, less than 6% in 2001, and slightly more than 1% in 1997[7]. Approximately 48% of spot cargos went to the U.S. market in 2003, 32% to Asia and 24% to Europe. The higher proportion of spot cargos going to the U.S. market was to take advantage of the relatively higher gas prices in the U.S. in 2003. It is projected that short-term trade will continue to grow, especially in the U.S. and European markets, and could reach 15% to 20% of total traded LNG over the next decade. Chart 4 illustrates the dramatic increase in short term trade to the U.S. over the years.

Chart 4: Growing Short-Term LNG Trade



Source: EIA

Global Gas Price Convergence?

Unlike crude oil, which is a commodity and has a unified, extensive and highly liquid world physical and paper market, natural gas currently has three distinct and relatively independent regional markets. LNG prices are benchmarked to competing fuels.

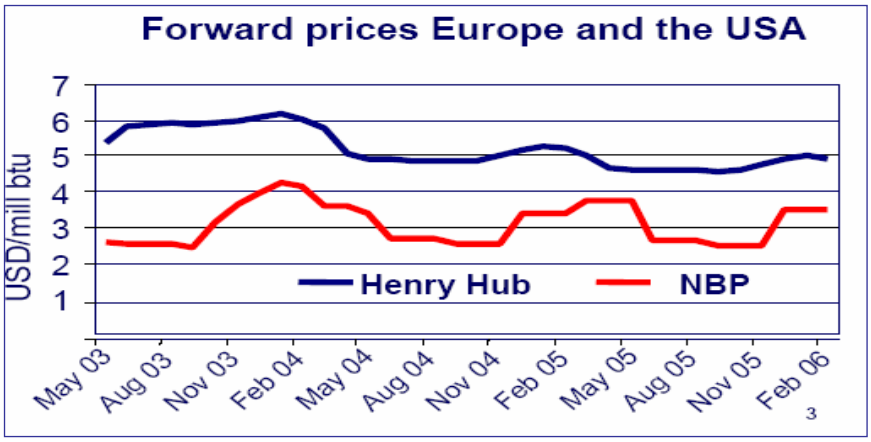
In the Asia Pacific, the oldest LNG market, LNG prices are linked to imported oil prices. Asian LNG pricing formulas generally follow an "S" curve, which mitigates, to a certain extent, the impact on the LNG price of extremely low or high oil prices. For instance, the GSPA between Ras Gas II and India's Petronet includes a crude oil price ceiling of US$24/bbl and a floor of US$16/bbl with the crude oil price in the first five years of the contract is being fixed at US$20/bbl[8]. Asian LNG prices are generally higher than elsewhere in the world, but the entry of China into the LNG game is breaking the trend. Now new Japanese LNG contract appear to track the China LNG contracts.

In the U.S., LNG is competing against pipeline gas and the benchmark is the Henry Hub natural prices. For instance, the FOB LNG prices in the GSPA between the Equatorial Guinea LNG project and BG is principally indexed to the Henry Hub gas prices[9]. The Henry Hub prices are affected by supply and demand, weather, storage levels and many other factors, and have very high volatility. Both sellers and

importers to the U.S. market face this volatility risk, which can be very significant. For instance, the natural gas price collapse in the U.S. in the 1980s caused two of the four LNG receiving terminals in the U.S. to be mothballed, which were not re-opened until 2002 and 2003 when the gas prices in the U.S. went up significantly, due to the natural gas shortages in North America.

In the European gas market, LNG is competing with such fuels as low-sulfur residual fuel oil. However, with the liberalization of the European gas market, LNG is starting to be linked to natural gas spot and futures prices. For instance, the LNG price of the QatarGas II LNG Project, which exports LNG to the U.K, will be indexed to the National Balance Point in the U.K. European natural gas prices historically are lower than that of the U.S. and have lower volatility. Chart 5 compares the UK gas prices with Henry Hub prices in the U.S. over the medium term.

Chart 5: Gas Prices USA and Europe



Source: Statoil

The increased flexibility of LNG trade and the surge in short term sales will increase the interconnection between the three regional gas markets. However, regional gas price differences, which reflect the fundamental demand and supply balances, the number of customers, the shipping and storage costs, and price rigidity, will continue to exist. In spite of the existence of such differences, it is predicted that the regional price differences will not become too large due to the arbitrage opportunities between different markets. Therefore, it may be concluded that there is a tendency for the gas prices to converge. However, such convergence is as yet, still limited. It may still take some years before a unified "global" LNG market will emerge.

Impact of New LNG Trade: Issues Faced by New LNG Projects

The changing nature of LNG trade has brought about unprecedented challenges to new LNG projects. The ability of a proposed project to overcome these challenges will determine the degree of success of the project.

First, a new LNG project must have competitive economics. This is necessary for accessing markets. Accessing a market through securing a long term take-or-pay contract still remains the basic requirement for shareholder final investment decision and for obtaining financing, even though less than

100% commitment of the capacity may have become acceptable to sponsors and lenders. A cost competitive project can also mitigate risks faced by projects targeting the U.S. market, where price volatility, rather than volume, is the most significant risk. Being a low cost producer will be able to supply the competitive U.S. gas market even at relatively low gas prices, which will drive out high cost and inefficient projects. Since low cost has become a priority in today's LNG market, it is inevitable that only the most cost competitive LNG projects are able to obtain financing and built. Such projects usually have very low feedstock price, such as the projects in the Middle East and Africa. There is also no wonder that most of the projects are undergoing expansions, which benefit from reduced operating costs. Even recent green field projects such as Egypt LNG at Idku are pursuing fast expansions.

Pursuit of low costs also leads to the construction of much bigger trains to take advantage of the economy of scale. A significant component of delivered LNG costs is the transportation costs. Proximity to market has placed Atlantic LNG in Trinidad and Tobago in a very advantageous position among suppliers to the U.S. and European markets, enabling it to supply 73% of the LNG imports to the U.S. in 2003. However, the construction of larger and larger LNG ships has enabled more distant projects to supply the U.S. market cost competitively.

Next, gas-on-gas pricing competition has become a major issue for projects in the Middle East and Africa that target the U.S. or the European markets. Suppliers to the U.S market must accept prevailing gas market prices, which are affected a myriad of factors including weather, storage, supply and demand conditions. Although the U.S. gas market is the most liquid in the world, with many derivatives, and swaps that facilitate certain hedging strategies, there is no fundamental way to completely mitigate the price volatility risk.

The European natural gas market, which traditionally is governed by long term contracts, has also opened the door to an increasing amount of gas-on-gas competition due to the liberalization of the European gas market which began in 1998. The U.K. market is a potentially large market for LNG with high liquidity and gas-on-gas competition. It is expected that a spot gas market will be developed in Europe in the future, which will increase gas price volatility in the European market. However, Europe has a long way to go to see a gas market similar to the U.S. market because the EU lacks the extensive internal gas natural gas pipeline network of the U.S. This is largely due to the fact that historically transmission systems were designed to ensure security of national supply rather than cross-border transmission. Integrating and upgrading these networks to enable them to transmit gas across Europe will require estimated investments of US$5 billion for every 350 Bcf per year of additional supply to the EU. The EU gas market liberalization and the inadequacy of the cross border transmission may cause gas glut in certain regions, such as the Iberian Peninsula, and Italy. The fourth LNG receiving terminal at Bilbao, Spain opened in 2003, and two more terminals are being built at Sagunto and El Ferrol of Spain. Portugal opened its first LNG terminal in 2003 and has announced plans to double its capacity. The Spanish terminals have received capacity reservations larger than their existing capacity. It has been warned that supply of LNG in Spain could exceed demand by 35% by 2006. Italy has one terminal in operation but as many as 10 terminals have been announced although few of them will be built. The regional over supply of gas may depress gas prices in those areas, affecting the overall gas price in Europe.

Third, the buyers' preferences are shifting in the LNG trade. Although long term contracts are still the norm, buyers are demanding more flexibility in other terms. The first LNG terminal in Guangdong, Southern China managed to negotiated lower price through supply tenders, causing a downward pressure throughout East Asia. It is likely that the existing LNG contracts in East Asia will be

renegotiated when they expire. The buyers will require lower prices and more flexibility in purchase terms. The destination clause in European gas supply contracts are being removed, providing buyers of gas with more flexibility in reselling the purchased gas. Importers of LNG into the U.S. market have secured freedom of destination, and certain freedoms in shipping control. Spot cargo sales have increased dramatically over the years.

Fourth, access to a re-gasification terminal is still vital to the success of an LNG project. Access to a specific terminal is also access to a specific gas market. The location of a regasification terminal will impact the gas prices in that region. A new LNG project must lock up its re-gasification capacity, either through third party buyers, or through project integration. In the first LNG project in Equatorial Guinea sponsored by Marathon Oil Corporation and GEPetrol, BG is the gas purchaser, which has locked up the Lake Charles Regasification capacity in Louisiana, U.S.A., for the project. For the Qatargas II projected sponsored by ExxonMobil and Qatar Petroleum, ExxonMobil and QP have decided to construct the terminal in Milford Haven, the U.K., thus creating an organizationally integrated LNG project.

Fifth, shipping control has become an issue for new LNG projects in view of the destination flexibility. Should shipping be integrated, i.e., delivering ex-ship or should it be left with the buyers, i.e., selling FOB plant? At a time when spot cargo and short term sales are increasing, buyers normally prefer to control shipping, i.e., buying on FOB terms. This will provide buyers with the opportunity to conduct LNG arbitrage, selling to the highest margin market when such opportunities arise. However, how to define designated tankers and have access to shipping in case buyer defaults will be an important issue for the sellers to consider.

Sixth, how to cope with the increasing integration of upstream and downstream participants in the LNG chain? There is a tendency that the upstream resource owners are moving down stream through participation in regasification and gas trading, while the utilities and gas marketers are moving upstream to participate in LNG liquefaction projects. These are natural developments of risk sharing and diversification. A new LNG project needs to consider the pros and cons of moving downstream the chain and provide the opportunity for buyers to participate in the upstream liquefaction activities.

The changing landscape of LNG trade has changed the risk profiles of the LNG business. Specifically, the undertaking of price risk by LNG projects has increased risks to both equity investors and lenders alike because both the sponsors and lenders are moving into uncharted waters.

Representative Financing Structures for LNG Projects

Table 5 shows representative financing structures for LNG projects in the Middle East and Africa.

Table 5: Representative Financing Structures for LNG Projects

Project	Date of Financial Close	Project Cost (US$)	Debt	D/E Ratio	Primary Lenders
Existing LNG Projects					
Nigeria LNG (T 1/2/3)	1996	4 Bn	0	0/100	100% equity financed
Atlantic LNG (T 1)	1996	950 mln	600 mln	63/37	$480 mln ECAs, $120 mln commercial banks
Ras Gas (T 1/2)	1996	3.4 Bn	2.55 Bn	75/25	$1.2 Bn project bonds, $900 mln ECAs, $450 mln commercial banks
Oman LNG (T 1/2)	1997	2.5 Bn	2 Bn	80/20	$1.15 Bn ECAs, $845 mln commercial banks
Nigerian LNG Plus (T 4/5)	2001	2 Bn	1.06 Bn	53/47	$620 mln ECAs, $176 mln commercial banks, $100 mln AfDB, $160 mln local Nigerian banks
Egyptian LNG (T 1 at Idku)	2003	1.3 Bn	1 Bn	77/23	$600 mln comercial banks, $450 mln EIB
Planned LNG Projects					
Qatargas II	2004 (Anticipated)	4.9 Bn	3.4 Bn	70/30	$1 Bn commercial banks, $1.5 Bn sponsor senior loan, $900 mln ECAs
Equatorial Guinea LNG	2005 (Anticipated)	1.7 Bn	1 Bn	60/40	Target: 100% ECAs
Angola LNG	2005 (Anticipated)	3.5 Bn	1.75 Bn	50/50	Most likely balance sheet financing; possibly some ECA/bank debt

Source: TDJ

The following conclusions can be drawn from Table 5:

First, there is no consensus leverage ratio among LNG projects. Of the LNG projects that achieved financial close between 1996 and 2003, the debt ratio varies considerably, with a low of 0% and a high of 80%, demonstrating that LNG projects are highly complicated projects, which may have very different risk profiles depending on the unique features of each project. In this respect, LNG projects are very different from power projects which may have more stable debt ratios for project financing.

Second, ECA participation is essential to most of the LNG projects with debt financing. All the projects in Table 5 except Nigerian LNG Trains 1, 2&3 involve ECA financing. This is because such projects are heavy capital intensive projected located in developing countries which are difficult to raise debt financing with without some form of ECA political risk or comprehensive cover.

Third, capital market financing may not be available to most of the LNG projects. Of all the projects in the table, only Ras Gas utilized some capital market financing through private placement of bonds, and the rest are financed by bank financing.

Competing for Capital

The highly capital intensive LNG liquefaction projects compete against each other, and also against other large energy projects for capital. It is estimated that a capital requirement between US$35 billion and US$55 billion will be needed for the projects in the Middle East and Africa from now to the end of this decade. Clearly such a huge bill cannot be footed solely by the commercial banks which have their country exposure limits. On the other hand, most liquefaction projects are not able to meet the more stringent criteria for capital financing except in a limited number of cases such as Qatar or Trinidad and

Tobago. This funding gas can be filled up by the ECAs. Therefore, for new LNG projects, the ECAs will likely be a key part of the financing plan.

Conclusions

LNG is booming worldwide, and in the Middle East and Africa in particular. The Middle East and Africa region is predicted to become the largest LNG exporter region by the end of this decade with Qatar displacing Indonesia. Most of the expansion and new projects in the region are targeting the U.S. and European markets.

Long term contracts will continue to dominate the LNG trade. However, buyers have demanded and secured more flexibility in new GSPA contracts.

Currently the LNG market is still fragmented, and consists of several regional markets although there is a tendency of convergence of gas prices in the making and there is an increase in spot and short term sales of LNG cargos. However, the gas market in the world will not develop into a replica of the global oil market due to the unique features of the LNG market.

Cost competitiveness, gas-on-gas competition, shifting buyer preferences, shipping control, and market access are still the key factors of success for LNG projects. Competition for capital will be a key issue faced by the LNG projects in the Middle East and Africa. ECAs will be a key part of the financing plan.

[1] EIA, Poten & Partners' LNG in World Markets, and Oil and Gas Journal.
[2] BG website.
[3] Oil and Gas Journal, June 14, 2004.
[4] Shell, "The Changing Global Gas Market", Nov. 3, 2003.
[5] EIA.
[6] Marathon Oil Corporation press release on June 22, 2004.
[7] Oil and Gas Journal , June 14, 2004, and Poten & Partners' LNG in World Markets Jan./Feb. 2004.
[8] Poten & Partners
[9] Marathon Oil Corporation press release on June 22, 2004.