COMMERCIAL LNG: STRUCTURE AND IMPLICATIONS

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Global trade in liquefied natural gas (LNG) trade is growing in volume and strategic importance. In the last eight years, growth in LNG volume with has been accompanied by an ongoing transformation in its business character. The traditional project-utility chain model supported funding of facility chains for new LNG trades with tight bilateral long-term contractual commercial relationships between the LNG export project as seller and the monopoly-franchised gas transmission merchant or electricity utility as buyer. Through a process that Joseph Schumpeter would have described as creative destruction, new projects are being formed by LNG merchants – major energy companies who control facilities and retain title to the LNG through the chain. This new business model, called commercial LNG, is still evolving. It is being driven by the confluence of three trends: growing size and scope of LNG trade, lower costs through the LNG facilities chain, and the erosion of utility monopoly franchises in competitive inland natural gas markets.

This evolution is most advanced in the Atlantic Basin market. I will start by using developments here to illustrate the expansion of trade and facilities that has been much discussed. Then I will step back and show how that economic expansion has been matched by an evolution of business structures—who owns what and on what terms—and commercial structures—the structure of transactions between the businesses. This will show the transition from the traditional project-utility chain model to the emerging commercial model, and it will suggest some policy questions resulting from this evolution.

Atlantic Basin LNG Developments

The dramatic growth in demand for LNG in Atlantic markets (and elsewhere) has been driven by several factors, most prominently, the increasing demand for natural gas in electricity generation. At a delivered price as high as $4-$5 per MBtu, natural gas is the preferred fuel for base load electricity generation in combined cycle facilities. Beyond straight economics, natural gas is preferred at even higher prices because of environmental considerations, the rapidity of plant construction and relatively low capital costs to meet competitive electricity markets, and flexible dispatch over the daily load cycle. Natural gas is a wonderful fuel to produce electricity.

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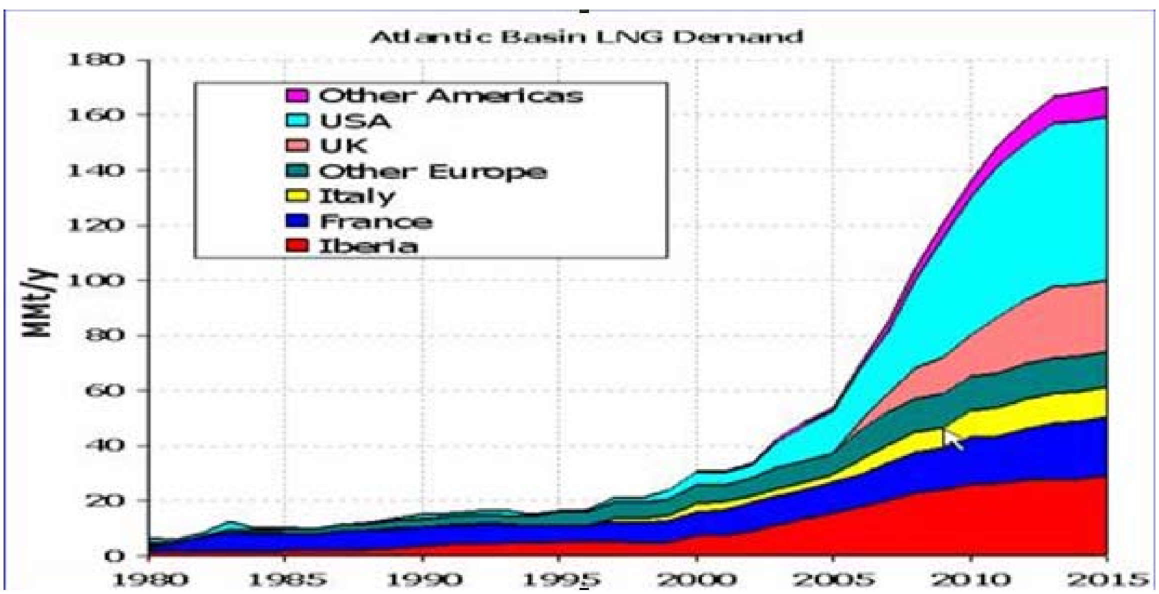
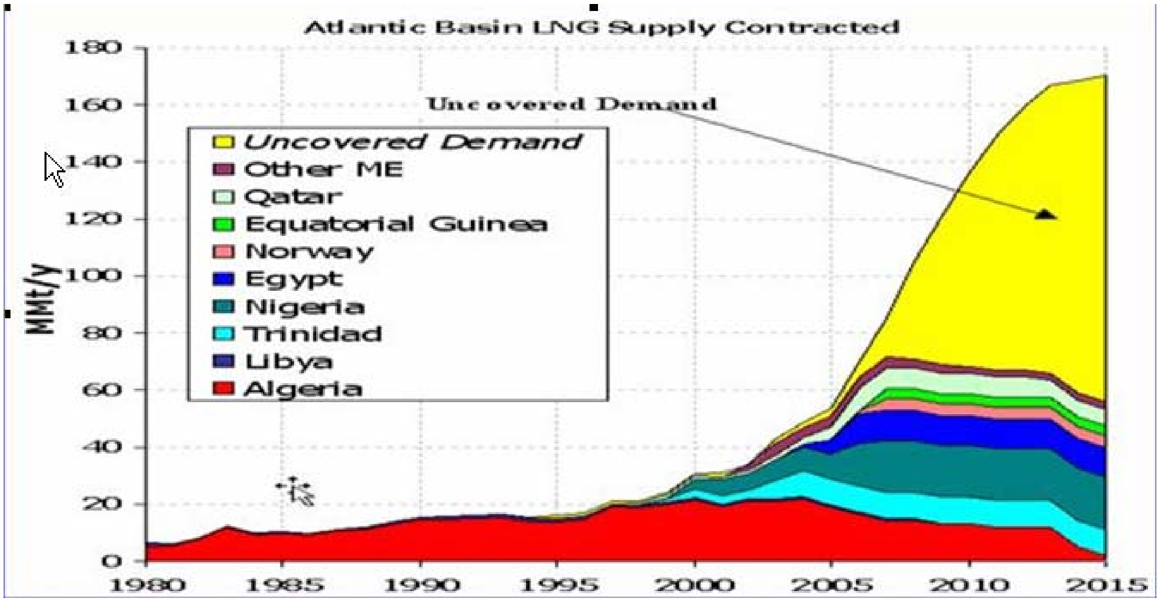
LNG is a growing component of global natural gas supply as growing markets reach out for new, more remote production. Indeed, the cost to supply LNG to inland natural gas markets is generally $3.50 per MBtu or less. Capital costs throughout the LNG supply chain have been cut in half in the last 15 years. Production costs for both oil and gas have dropped sharply with new technologies for seismic, horizontal drilling, and subsea completions. Pipeline costs are down. Shipyard competition has driven ship costs down. And, driven by the need to enter competitive inland gas markets, LNG supply projects are instituting increasingly competitive facility procurements from construction contractors and LNG process venders. This competition has cut LNG export project costs through simpler design and project management, and significant increases in scale.

The Atlantic LNG project in Trinidad, sponsored by Repsol YPF and others, originated contractor competition in front-end engineering design (FEED) for the LNG plant, and has set a new standard in reducing grassroots project costs. More generally, where in 1996, the standard liquefaction train had capacity of two million tons a year (Mt/y), today new LNG projects are installing 4-5 Mt/y trains, and Shell and Exxon are talking about new projects with one or more trains of eight Mt/y capacity each. The result is that LNG can compete with coal for base load electricity generation almost anywhere in the world, and in particular, in the growing continental natural gas markets of the Atlantic Basin.



To give a sense of the prospects for LNG expansion, Figure 1 shows the probable quadrupling of LNG demand in the Atlantic basin, with volumes rising from 40 Mt/y in 2003 to 160 Mt/y a decade later. There will be major growth in demand in the Iberian Peninsula, significant growth in France despite her traditional focus on nuclear power, and the potential for massive LNG import growth in the United Kingdom as growing demand and declining production of natural gas moves the UK from exporter importer stature. In North America, maturing production of natural gas is failing to keep pace with demand.

On the supply side, Figure 2 shows projected growth in LNG supply through 2015. The reserves are more than adequate, and there is a great deal of new and expanded supply project formation activity. Out of the eight current export projects serving Atlantic markets, four are expanding, in Nigeria, Oman, Qatar, and Trinidad. New projects are being built in Egypt and Norway, and new projects are proposed in Angola, Equatorial Guinea, Iran, Nigeria, Venezuela, and in Algeria (which is finally returning to the new project market after the debacles of the 1980s).



In short, the fundamental economics for LNG trade expansion are fine: there are ample supply resources, proliferating export project development efforts, and demand growth potential which is very large. But the funding of new LNG supply projects still requires assured shipping and import access to markets and sales revenue.

Shipping is not a problem and is growing apace. More than 80 new ships are scheduled for delivery between 2002 and 2007, adding to the current fleet of 160 vessels. The changes in ownership are even more significant than the growth in numbers. In addition to shipping dedicated to long-term contracts, at least 15 vessels will be acquired by big players such as BP, BG, Shell, and Tractebel for trading. And as these big players develop LNG merchant trading capability on their own account, they are developing control of uncommitted capacity beyond supply access and ships. For the first time, import facilities are also controlled by merchant traders with the discretionary capability to go to markets where the arbitrage opportunities are good. This contrasts with the older project model in which ship ownership and dedication to specific trades were embedded in the bilateral contract between a project and a buyer.

The potential bottleneck is new LNG import capacity. In Europe, LNG import capacity is expanding massively. There are three large LNG import terminal projects in the UK, two in France, two or three in Spain, and plans and proposals for several in Italy.

In North America, where the continental natural gas supply outlook is more limited, nevertheless prospects for new LNG import capacity are more conflicted. Recent and welcome changes in US Federal laws and policy encourage LNG import terminal construction, by allowing privately controlled ("non-jurisdictional") LNG import projects. But, as with other US energy infrastructure, there are federal-state jurisdictional conflicts over siting and permitting.

Plans at the four existing US import terminals will expand annual capacity to 1.3 trillion cubic feet (Tcf), or about 26 Mt, to accommodate new supplies from Trinidad, Egypt, Norway and Qatar. There are another five terminals in various stages of approval in the Caribbean and in the Gulf of Mexico. A host of proposed projects on both coasts facing various degrees of development and local resistance. LNG advocates on the coasts have not been successful in making the political case that LNG is safer than, say, gasoline or anhydrous ammonia—and that if these areas do not import LNG, the country may see a great upsurge in coal-fired electricity generation. Projects in the Gulf of Mexico, where people are used to energy projects, are likely to fare better. ChevronTexaco, ConocoPhillips, ExxonMobil, and Shell are all developing import projects in the Gulf to be supplied from new export projects in Africa, the Middle East, and Venezuela.

The recent growth in LNG volumes has been accompanied by a growth in short-term trading -- by which we mean arms length trades outside of existing contracts using existing capacity through the chain between projects or merchants with and third-party buyers. The traditional project-utility chain structure always generated some spare capacity; but its production was typically traded within the long-term bilateral contract framework. True short-term trading emerged in the late 1990s, and such trades have expanded from two to about eight Mt/y, about 7 percent of the market. On the demand side, growing US natural gas market liquidity offers both a destination and financial futures platform for such trading.

It is now possible to see the arbitrage at play in the trading. The thing to keep in mind going forward is that LNG offers the only physical arbitrage between continental natural gas and electricity markets, and so the embedded optionality value of uncommitted capacity through the chain is high. And the keys to exploiting that optionality are market liquidity and destination optionality within the contractual terms of the project business and commercial structures.

In Asia-Pacific markets, where gas markets are smaller and utilities remain dominant, LNG export projects rather than gas producer/merchants remain the dominant sellers. Short-term trading is growing to meet seasonal demands in South Korea, demands from the nuclear shutdown in Japan, and a supply interruption in Indonesia. Merchant trading appears in Shell "wedge" volumes from Australia NWS, and potentially, from the Japanese trading house participation and liftings from Oman's Qalhat LNG. Japanese utilities are joining Kogas in owning ships and lifting FOB sales under more flexible terms. Indexed pricing in this market will be challenged by the opening of trading from Asian producers to the west coast of North America.

Emergence of Commercial LNG

How have these changes taken place? It is useful to reflect for a moment on how business and commercial structures develop in any energy trade. All energy businesses share common structural features. They are capital intensive, with about 70 percent of value added by capital services. They require a facilities chain from production, through transportation, distribution, and use. Early on in there industry development, these chains are bilaterally committed; that is, a specific supply project is linked by design and commercial commitment to a specific market. Managing this chain, and precluding opportunistic threats by participants, requires an integrated business structure. Within a country, this can be provided by a vertically integrated, regulated monopoly; internationally, the early oil business comprised international companies integrated from the well to the pump, but natural gas and electricity were regulated domestic monopoly-franchised utilities. In these chains, suppliers and buyers must be connected by long-term contracts. This structure is the project-utility chain model.

For the supply side, such a model assures a creditworthy revenue stream; for the demand side, it assures reliable, non-opportunistic supply. The project-utility chain business structure consists of an export project, which is typically a joint venture between a supplier (an international or national oil company), and buyers, which are typically monopoly franchised utilities or merchant traders. Funding of facilities through the chain is secured with bilaterally dedicated services and committed revenues.

Now, what went on in LNG under the project model? Remember that LNG is not a commodity; it is a means of transportation. Its economic function is to move natural gas from a low-cost, low-value resource to a distant, high-value market. The resource has to be low-cost to provide the margin to pay for the transportation, and it has to be low-value to favor export. Markets have to be distant because otherwise natural gas is moved by pipeline; markets have to be high-value to pay for the expensive LNG infrastructure. Early LNG supply project development was costly and technically challenging. Early trades offered little rent cushion; in fact, they came into the market at negotiated pricing premiums.

Import terminals and service facilities for electricity generation and citygas distribution cost several billion dollars, on the same order as the outlay for supply. Distant markets imply that trade is international. As a consequence, it has to be contractual, not socialized, and it has to start big because of the necessary scale in facilities. Unlike any other energy business, LNG can't start incrementally in local markets, because its purpose is transportation.

Early projects on the demand side are therefore owned by monopoly utilities; arms-length business in an isolated market. And the whole logistical chain, costing perhaps $5 billion or more, must be created and financed simultaneously, with construction funding dedicated four or more years in advance. This requires a special kind of business structure and financing. The key is a creditworthy sales-and-purchase agreement (SPA). In the standard SPA, quantity risk is allocated to the buyer, who assumes a take-or-pay obligation to assure utilization of the chain. Price risk is taken by the seller. Pricing is oil-indexed, which requires a "social contract" in which regulators, customers, and politicians agree that the utility can charge endues customers on that basis. This business structure is very costly to buyers because the rigid delivery means no laying off or acquiring additional LNG to mitigate demand supply mismatches. It is also costly to sellers because rigid destination restrictions limit arbitrage.

In the project-utility chain structure, there is little scope for opportunistic trade responding to contemporaneous competitive market values. A competitive commercial market for an energy commodity requires a competitive commercial market for transportation services. The starting point in the move to a commercial model is the unbundling of transportation assets and services. This was true in oil, later in natural gas, and currently in electricity. For example, the oil business started to open up after the 1956 Suez Crisis when Greek ship owners started to permit third-party FOB purchases at terminals in the Arabian Gulf. Ultimately, the entire oil business became unbundled. Natural gas unbundling was next. In the United States, in 1985 U.S. Federal Energy Regulatory Commission Order 436 mandated pipeline open access, and now liberalization in the European markets includes a mandate for third-party access as well. Finally, in electricity, we are accepting that its transportation and congestion pricing requires unbundling with the use of financial transmission rights (FTRs).

Now consider the commercial LNG model. Commercial LNG accommodates opportunistic exchange to meet current market conditions. This requires a LNG merchant business structure to control production, liquefaction, shipping, and import capacity that can be used flexibly. In addition, with the replacement of the buyer monopoly utility, the merchant must take up or arrange for the marketing functions – demand aggregation, sales, and trade credit (replacing project credit in the old model). Neither LNG supply projects nor importing monopoly utilities are equipped to manage these cross-trade functions.

Thus, enabled by lower costs through the LNG chain, expanded LNG market scope, and accessible natural gas markets, major energy companies who are the gas producers in supply projects can move downstream, and major gas buyers can move upstream to become LNG merchants with capacity control across multiple trades, in some combination of multiple supply projects, undedicated shipping, and multiple import location access.

This changes the role of the LNG export project, which takes on a different business structure and commercial function. In one version of this new model the LNG export project becomes a tolling facility, selling liquefaction, storage, and loading services to the gas producer/LNG merchant. Natural gas producers rather than the projects become the sellers. And LNG merchant traders, who have control of facilities assets through the chain, evolve as buyers. In the Atlantic basin in the late 1990s, new trades were formed by Repsol YPF, BP, BG, Gas Natural, and Cabot LNG (later Tractebel LNG), who controlled their own shipping and moved the shipping among projects. The LNG plant is simply paid a processing fee, and the upstream producers such as BP, Repsol YPF, BG, and others are now selling — and they themselves often participate in buyer import projects. This tolling structure has been adopted the Egyptian LNG projects, with BG (to Italy) and BP (to UK) as the merchants, and SEGAS project, with the Spanish utility Union Fenosa as the merchant.

An alternative is for LNG project partners to buy LNG from the project and transport and sell through import projects that they form. In the Qatar, ExxonMobil with QP as well as ConocoPhillips are developing such structures for export to the UK and North America.

Who are the players in this new world? As Table 1 shows, it is no longer the "projects-to-utilities" play.

TABLE 1: Representative LNG Merchant Positions

Merchant	Export positions	Merchant Shipping	Import positions
Supplier side			
BG	Trinidad (Atlantic LNG), Egyptian LNG, Iran (prop.)	Yes	Lake Charles, LA Elba Isl. GA, Brindisi, Italy (prop.)
BP	Trinidad (Atlantic LNG), Egyptian LNG, Angola LNG (prop.), Abu Dhabi, Indonesia, Iran (prop.),	Yes	Bilbao, Spain, Cove Point, MD, Grain UK
ExxonMobil	Qatar, West Niger Delta LNG (prop.), Angola LNG (prop.), Indonesia	Yes	UK, France, and Gulf of Mexico (all prop.)
SONATRACH	Algeria	Yes	El Ferrol, Spain (prop.), Grain UK
Shell	Nigeria LNG, Venezuela (prop.), Oman LNG, also Brunei, Australia NWS, Malaysia, Sakhalin	Yes	Elba Island, GA, Altamira, Mexico (prop.)
Buyer side			
Gdf	Snohvit, Egyptian LNG	Yes	France (2)
Repsol/YPF	Trinidad (Atlantic LNG)	Yes	Bilbao, Spain, El Ferrol, Spain (prop.), Altamira and Lazaro Cardenas, Mexico (prop.)
Tractebel	Trinidad (Atlantic LNG)	Yes	Zeebrugge, Bel., Everett, MA, Bahamas-FL (prop.)
Union Fenosa/ENI	SEGAS LNG (Egypt), and purchase from Oman LNG		Sagunto

Rather, it is the majors such as BG, BP, Exxon-Mobil, Sonatrach, and Shell that start as suppliers and move downstream from project positions through their own shipping to captive import projects. And at the same time, the buyers are moving upstream. Gaz de France (GdF) is taking equity LNG from the Norway Snohvit project into its Atlantic ports. Repsol YPF moved upstream into the Trinidad Project and manages its own ships. The pattern continues. In this commercialization, "gas for sale" signs are not installed and customers do not simply line up. Rather, what does happen is that the major players are controlling capacity through the chain.

Under the commercial structure, most of the trade will be as long-term contracts, but the character of those contracts will change. There is now discretionary trading, with many variables. Negotiations are between principals who know where the production gaps are, who know where the offloading gaps are, know where the ships are. So this is still a principals' business, and they all have the same rolodex. Long-term contracts will evolve to permit and share arbitrage, which will loosen destination restrictions. There will be liquid markets that support some spot trading. Spot trading will remain, but within a context of a larger business. True swaps involve too many people.

Policy issues

The emergence of the LNG merchant structure raises new policy issues:

In North America, import terminal siting is a key issue. The "not in my backyard" problem for LNG (as well as for electricity transmission) highlights the conflicts in the federal and local dimensions of the regulatory structure, and will create increasingly acute problems in both of those markets, absent an aggressive rationalization of the jurisdiction policy.

Project finance is replaced by trade finance, but with new characteristics. Commodity futures markets are always thin on the short side, and so the vanishing of the project structure created new demands for finance. The disappearance of the asset-owning merchant traders after the Enron collapse has created very thin futures markets in natural gas and made commercial trading harder.

Demand aggregation, or market power, becomes a critical issue. For example, in Europe there is a fight among both natural gas pipeline suppliers and LNG suppliers over destination clauses. The suppliers—Sonatrach, the Russians, the LNG projects—want to keep them, and the European Commission wants to abolish them. The question is who will share the rents from arbitrage.

Market access remains a critical unresolved issue. Third-party access to import terminals is not the same as common carriage, and it provides an incentive to owners to fill up their own terminals with theirs own contractors' supplies.

At the base is the question of attaining efficient competition. Whether creative destruction will go that far remains to be seen. However, the trend in Europe, despite a decade of liberalization, shows the market power of emerging national champions.