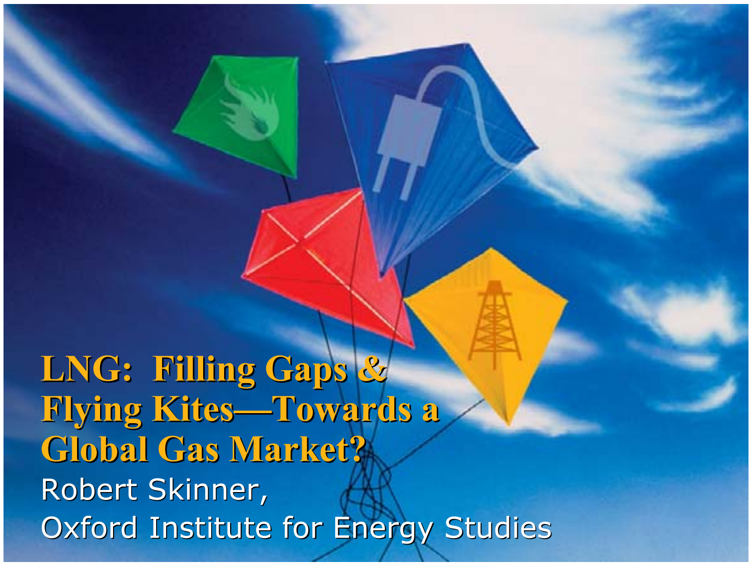
NOTES FOR DELOITTE PRESENTATION
"LNG: Filling Gaps & Flying Kites—Towards a Global Gas Market?"



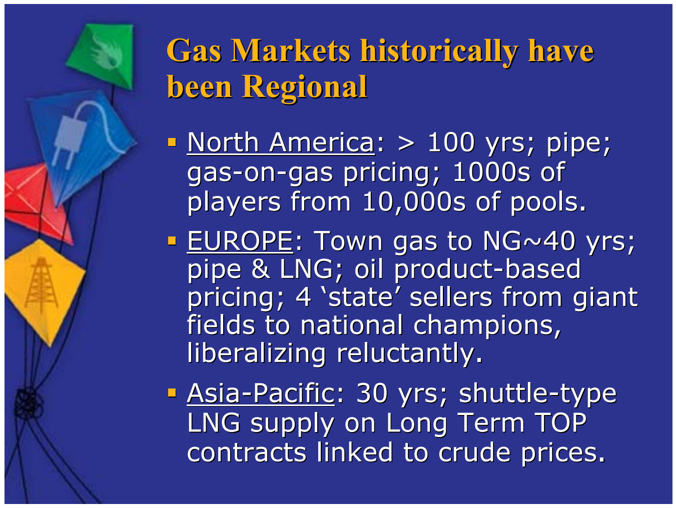
I would like to thank Deloittes for inviting me to speak at this conference. I would also like to thank them for their continued support of the Oxford Institute for Energy Studies, an Educational Charity based in Oxford, England. The organizers asked me to talk about the outlook for LNG, its influence on regional gas markets, whether we are headed for a global gas market, and what might be some of the investment implications.

I liked the organizer's slide template so much, I decided to use it in the title of my presentation. The imagery of flying kites all tangled together illustrates some aspects of today's natural gas sector in general and the LNG business in particular. As we shall see there are many players out there flying kites in what they obviously believe will be steady winds taking the natural gas value chain to new heights.

I will discuss the outlook for gas only briefly because it is presented so often at conferences that everyone here must have heard it before. I want to discuss the key developments and issues related to the **outlook for LNG**, and development prospects in the various gas markets, and address the question, **"Will we have a world gas market?"**

Everyone sees a great future for gas. It is the fastest growing conventional form of Primary Energy in most energy projections (2.7 – 3%). This is largely because electricity is the fastest growing form of energy in final consumption (~2.5%), and gas is the preferred fuel for power generation (4 to 5%). However, the gas reserves are not *here* near markets, but are over there, and a long way over there. Resolving this tyranny of distance is the investment challenge in gas, and that means for the foreseeable future essentially LNG. This is not to say that pipelines will not be constructed—they will, but to address the key gas supply gap, North America, apart from gas from the Arctic, LNG is the only means of getting the needed gas to this market. Long distance gas supply projects are expensive and take a long time to put together: they create a co-dependence where the consumer's concerns about security of supply match the producer's concerns about security of demand.

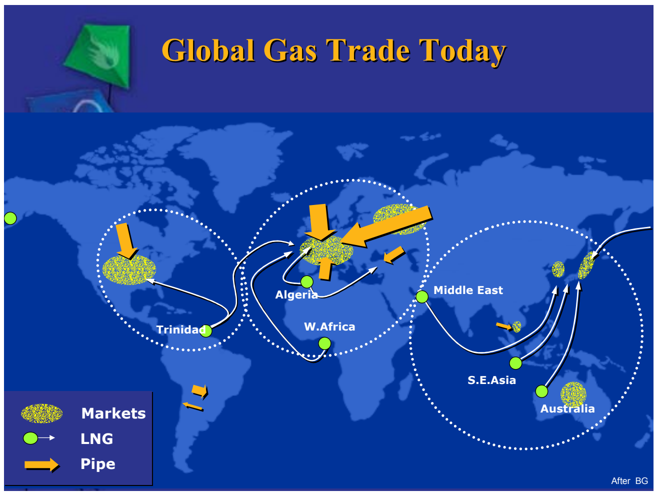
As we are so painfully aware, you can't go very far on this planet without encountering political strife and tensions. So, not surprising, natural gas supply is fundamentally all about addressing geopolitical issues, and this accounts for a good measure of the drag on putting supply projects together. It seems almost universal that the supply end of the gas chain is burdened with political risk; the other end increasingly faces regulatory risk that is compounding the ever-present market or volume risk. I can think of few projects in the world where the over-riding factor determining a project's viability is not political. Solve the politics in gas supply and the rest is easy.



Let's take a quick look at today's gas markets and quickly review how we got here. Gas is sold in regional markets with different requirements and different histories. Here in **North America**, consuming >30% of world gas supply, we have had a natural gas business for more than a century. It has been based on pipeline gas, although ironically the first LNG cargo was shipped *from* the U.S. to the UK back in the fifties. Today there are 1000s of producers selling more than 75 Bcf/d from 10s of 1000s of rapidly declining, small gas pools, to 100's of thousands of customers in a very liquid and volatile, continental, liberalized market where the price is largely determined by gas on gas competition.

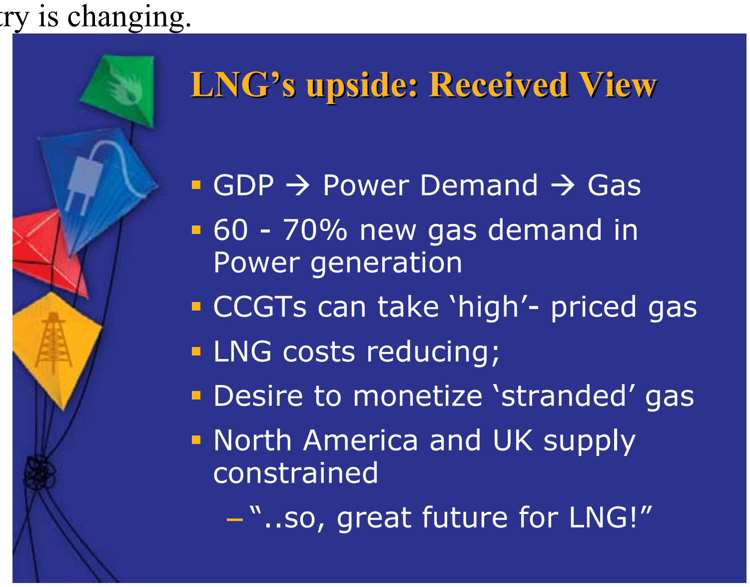
The **European** market is much younger; about half the size of North America's and has developed on the back of a coal-based town gas system. Since discovery of natural gas in the North Sea, Europe's gas market has grown dramatically to about 15% of world consumption. To finance the very costly offshore gas developments, based on giant gas fields in the North Sea, or in the case of Russia, super-giant fields, the buyers, mostly national champions or state-owned gas utilities, entered into long term take-or-pay contracts with producers who, for more than 85% of the gas supply, are essentially four states—Norway, Netherlands, Algeria and Russia. The European Commission has been trying to create a Single Market for gas and for power, and it is fair to say that there has been some increase in the number of suppliers, but this is proving to be a struggle given the market incumbents' power and interests in the status quo, and the tacit support of their host governments. Gas in Europe has been priced based on the prices of competing fuels. At current oil prices the incumbents at both ends of the pipes have little interest in changing the system.

In **Asia-Pacific**, consuming almost an amount equal to Europe and growing the fastest, the gas market was launched in the early seventies by Japan as a conscious policy decision aimed at energy security. In 1973, ***75%*** of Japan's electricity supply was generated in oil-fired plants. The government backstopped and encouraged consortia of electric and gas utilities to enter into rigid, long term take or pay, shuttle type LNG contracts with supplying consortia, firstly with producers in the region (including Alaska), then later in the Middle East. LNG prices were based on a basket of crude prices imported into Japan—the Japanese Crude Cocktail. Bear that in mind when we consider new contracts and how Japanese buyers might wish to approach the price basis in the future, given that their business environment is changing, along with that of the LNG business in general. We should not forget that there are other gas markets in the region: Pakistan and Bangladesh have had internal gas markets for about 30 years, and Australia is struggling to find the right rules to foster a country-wide market in what is a smaller version of what the world faces—resources a long way from the market. So the region is best viewed as a group of, as yet, unconnected domestic markets.



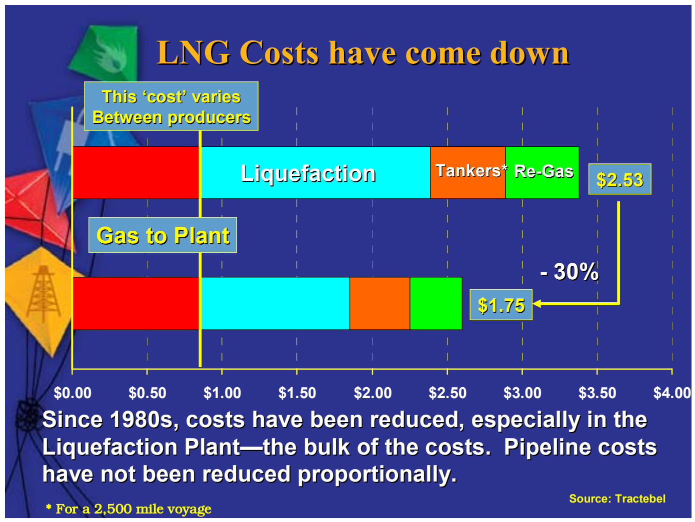
This **map**, courtesy of BG Group, with a few additions, illustrates today's three regional gas markets.

So, three very different markets with different histories, and they are changing because the LNG industry is changing.



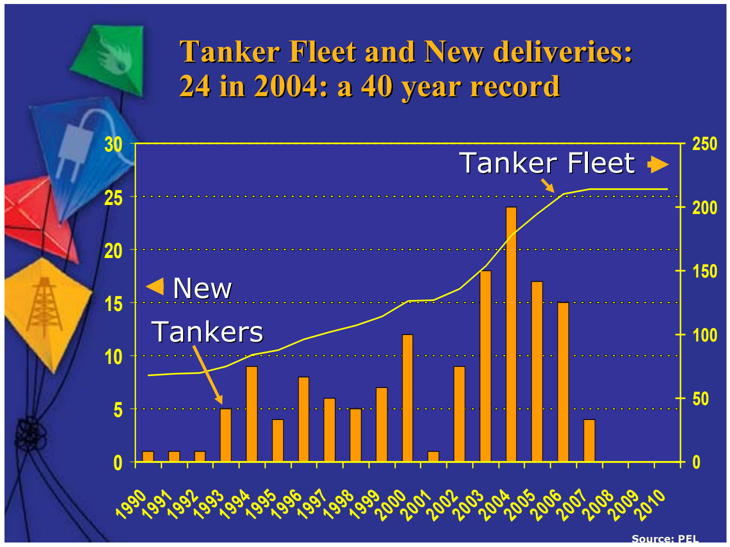
The received view on LNG is that it is all upside. Modern economies are electricity-intensive and gas is the fuel of choice for power generation. Two thirds of projected growth in gas demand will go into power generation, we are told. Combined Cycle Gas

Turbines, with their low capital cost and quick build, can handle the prices associated with LNG-derived gas. LNG's costs are coming down; companies and states want to monetize their so-called stranded gas. Major oil companies, increasingly facing difficulties in replacing reserves, like what an LNG project does for their reserve bookings. Finally, to underscore the enthusiasm for more supply, it appears that the two countries (UK and US) that have dashed for gas in the power sector have hit a gas supply wall and are looking to imports to fill the gap. So, a great future for LNG.



As I mentioned, LNG costs have decreased since the early nineties. This slide based on Tractebel's numbers says 30%; others say by even more. It underscores the following points:

1) Most cost savings have come in the most expensive link in the chain, liquefaction, largely owing to the development of larger compressors. Also, the size of the average new train has more than tripled.
2) The bulk of the CAPEX (nearly 60%) is in the host country; only 10% in the consuming country. Thus, given where the resources are, country risk is where the financial load is the greatest. While financial risk is relatively small at the other end, there is market risk assuming you can get approval for the terminal. This distribution of risks will increasingly affect just who can play in this game.
3) Shipping costs have come down largely because of competition between ship yards, and the Asian Crisis.



This year, 2004, will be a bumper year for new **tanker** deliveries—24—an all-time record. Tanker costs have reduced by ½--from \$320 million per tanker (\$2200/m^3) to \$160 million (\$1100/m^3), mostly because Korea, having entered the tanker building game to compete with the 'cost-didn't-matter Japanese yards', experienced a major currency devaluation (74% ref \$) with the Asian Crisis in the late nineties.

The drop in demand with the Asian Crisis, together with the continued de-bottlenecking at liquefaction plants, generated some slop in available cargoes. This added to the chronic availabilities from Algeria, a carry-over form Sonatrach's long-running disagreement with US buyers dating from the 1970's. So, with the growth of spare cargoes and sellers willing to move them for out-of-pocket costs, the makings of a short term-trade arrived. The industry at first refused to call these 'spot' cargoes because they did not like what the term, 'spot' implied; namely, a major shift in comfort for them.

So, the LNG business and markets are changing. There are more players entering the market bringing with them even more spot cargoes. 'Spot cargoes' usually come available during ramp-up of a new project; also, additional volumes due to contract expiries will appear with a vengeance around the end of the decade, especially in the Pacific Basin.

A fourth, and important source of spot cargoes, is the merchant component of new supply. The Trinidad Atlantic LNG Project marked an important milestone in the evolution of the LNG business, when the project was sanctioned without first having contracted buyers for all of the output. There were other innovations at Trinidad (competitive bidding for EPC, and some new technology), but starting up an LNG plant without fully committed homes for the output was unheard of. It signalled the readiness of producers to take risk. Sakhalin and Train III of Egypt's LNG project are other examples.

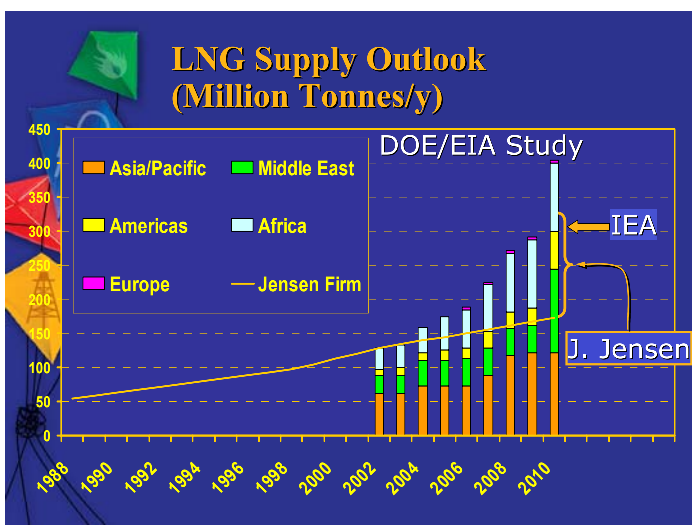
The LNG business is far too small for anybody to launch a fully merchant LNG plant, however we are seeing merchant players entering the business, for example buying tankers that are not part of a dedicated LNG chain or shuttle. They are not purely flying kites—one would expect that they have entered into some form of off-take arrangement with LNG producers. With the Japanese and South Korean economies beginning to recover on the wave of growth propagated by China, we should expect to see greater demand for LNG; however, at current oil prices LNG will tend to come after coal and nuclear in the merit order, so buyers will want to winkle as much flexibility as possible out of their contracts. Also, with the US east coast terminals open for business again and expanding and with the growing arbitrage opportunities, producers may also want flexibility. Thus the forces are there for a shift in the LNG market to the Atlantic Basin.

Another factor forcing change in the business is gas and power sector reform and market liberalization. In competitive markets LNG buyers, such as power companies and gas suppliers, no longer have captive customers to whom they can pass on their LNG obligations. They can no longer take all of the market or volume risk. We are seeing suppliers stepping in and investing in terminals (Shell in Mexico; BG in Lake Charles and Milford Haven in Wales; EXXON/Mobil in Wales). Therefore, the risk in the downstream is moving to the upstream. While many oil companies have aspirations to get on the LNG bandwagon, not everyone can absorb the combination of upstream country and project risk plus downstream volume risk. However, the market capitalisations of most of the top 5 or 6 companies are now large enough to take on market risk at the liquefaction end, something they could not contemplate prior to their respective mergers. At the same time, buyers are prepared to move upstream and take a share of the supply end (China in NW Shelf; Korea Gas in Qatar). Thus the effect of market reform is to distribute risk of the participants along the LNG chain.

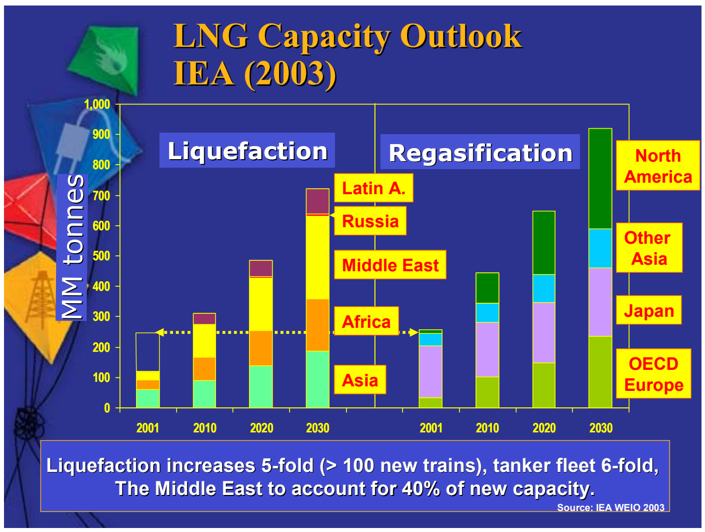
Increasingly, the pricing reference or basis is shifting from oil-based pricing to gas-on-gas price competition, by virtue of the North American re-entry to the business, and with it, inoculating the LNG business with a lot more seasonality and volatility. Gas on gas competition will be compounded after 2007 when the Second Gas Directive comes into effect in Europe.

I should mention **technological change**, something that is invariably underestimated in projections. I mentioned earlier the increased train size. Noteworthy has been the innovation in project planning and financing to shorten the time to market : Nigeria LNG took nearly 30 years; Egypt LNG will be 6 years from the original MOU with the government to first LNG—mind you, for Nigeria, the net back price just could not cut it, until tanker costs came down and market prices firmed upwards.

Tanker size is increasing. EXXON/Mobil proposes to nearly double the size of tankers for RasGas II. Other innovations include floating liquefaction for offshore discoveries, to be employed at Norway's Snovhit project. Recognizing the difficulty of getting approval for shore-based re-gasification terminals, the industry has come up with the Energy Bridge Re-gasification Ship concept. Further innovation would involve storing the gas from these EBRSs in sub-sea salt caverns in the US Gulf thereby getting 'round the very high cost of storage tanks—the largest chunk of terminal costs (although salt caverns don't come cheaply either).



I continue to monitor various LNG projections. Most seem to use the same source—sort of like an 'LNG kite-flyers Almanac', prepared for the US DOE/EIA—basically a list of all the announced projects in the world. Jim Jensen, who is associated with the Oxford Institute's Gas Research Programme, uses a Firm, Probable and Possible break-down, which I have shown on this slide. These three projections imply annual capacity additions of 1, 2 and 4 plants per year respectively at 6 MMt/plant. If all the announced projects identified in the US DOE/EIA study were to go ahead, LNG capacity would increase by over 220% to 405 MMt/y from 2002.



This next slide illustrates the IEA's view of where the new plants will be located; mostly Middle East and Africa. The IEA's bullish and somewhat mechanistic model projects a 130% increase in supply by 2010—but a 5-fold increase by 2030. The IEA has world LNG production in 2030 nearly equal to the total current OECD natural gas consumption.

It illustrates the following:

1) current re-gasification capacity exceeds supply (this imbalance will worsen);
2) the shift of weight to the Atlantic Basin; and
3) in the longer term the Middle East (basically Qatar and Iran) will become the largest supplier of LNG.

[The IEA in its recent World Energy Investment Outlook projects $16 Trillion of energy investment needed out to 2030, of which $3 Trillion will be in natural gas, and $250 in LNG. Of this, $100 billion will be in OECD countries. This is very capital intensive business. It is technology heavy in two senses: it is technology intensive and the material is big and heavy and special.]

Let's look at the major gas markets again, this time in reverse order, to see where the growth is and what some of the issues might be.

Start with the traditional LNG market, **Asia-Pacific--**actually a 'region' of several small markets—it is not yet a regional market, although there are grand pipeline proposals to connect its sub-regions. They amount to:

- multi-billion dollar pipeline projects (west-east pipe in China—under construction, pipes from east Siberia to Japan and/or China, pipes across the Indian Ocean or island hopping pipes around Asia);
- on greenfield sites;
- transiting countries not convinced of the benefits of helping their neighbours, sometimes traditional enemies,
- and targeted at markets that are either
  - going through liberalization,
  - and/or are small,
  - often where prices are based on coal and don't reflect costs;
  - where the government favours domestic gas, and
  - has not sorted out among the different levels of government who is responsible for gas regulation.

India and China, let's remember, are very small markets. They have enormous upside for $2 gas, but that's not LNG. As gas markets, they are starting from a very different position than did Japan and South Korea in the early seventies; the latter replaced distant oil imports with closer-by LNG in which their firms had invested; China and India would be using LNG to substitute for an indigenous fuel—coal, although recently a very large share of new power generation for the industrial sector is in diesel and middle distillate-fired generation sets.

Turning to **Europe**, while EC officials in Brussels fret about security of gas supply, they have a lot of gas around them and many countries—11 or 12 at last count—currently supplying their gas. The transit states of Ukraine and Belarus seem to pose the greatest problem for Russian gas and for Europe's security of supply. This is why Gazprom wants to build the trans-Baltic north European pipeline, even though it is very expensive supply. Meanwhile, there are new suppliers and new proposals for pipe from North Africa. These could result in the freeing up of North African LNG for North America. European gas demand projections normally see 60% of new gas demand in power, but that is just not happening except in the Iberian Peninsula and not much new growth in gas fired power is expected well out beyond 2010. Are we seeing the emergence of a gas bubble in Europe? More than one company executive fears so.

The UK is a separate case. It will soon be a net importer and that worries some, but there is the potential for oversupply: LNG to Wales and the southeast; new pipe gas from Norway, the Netherlands and from an expanded UK Interconnector, with increased supplies from Russia into Europe. Coal imports to the UK are increasing, as well. Why did the buyers of UK coal plants install FGD? To shut it down? Doubtful.

North America. Gas supply has hit the wall. I don't want to spend too much time on why—to summarize:

- rapid decline rates,
- declining new pool size,
- lack of access to the resource;
- slow approval process where there are prospects and the hope of access (Rocky Mountain Basin, San Juan Basin)
- disappointment from Canada's Western Sedimentary Basin where small players are simply drilling shallow wells for next week's cash flow.

It took your bespoke Energy Minister, Alan Greenspan, to point it out—elasticity of gas supply has been greatly over-estimated. Demand destruction has, on the one hand taken some of the pressure off. But, over 220 GW of new gas fired capacity has been constructed in the last 5 years and if the price was lower, those turbines could be burning more gas than could possibly be delivered through the terminals available or even those terminals remotely possible by 2010.

As for terminals, I have tired of up-dating my map, so I have left it out of this presentation. There are more than 40 proposals. Some 20 Bcf/d of import capacity can be classified as existing, expanding, under construction, or before either the FERC or the US Coast Guard. Another 20 Bcf/d of terminals can be put in the category of kite-flying or claim-staking. There is nothing wrong with that. It signals intention and interest of being in the game; it tests the waters, animates debate and has the effect of narrowing down the race.

America was dealt a bad hand when it turns out that the ends of gas pipelines, where terminals are most needed, are in places like New England and California, where the NIMBY syndrome is the strongest. Whether neighbouring Mexico and the Canadian Maritime provinces will want to serve as gas bridges to these project-averse regions, and more importantly whether the extra transportation costs involved will simply erode away the basis advantage, remain to be seen. The basis differential between Henry Hub and Boston is usually about 30 to 40 cents/MMBtu. There would have to be very sweet terms and dramatically lower costs to achieve an ex-re-gasification plant price low enough to offset the extra pipeline costs to move the gas to Boston from the Maritimes.

I believe there will be more than enough terminal capacity to meet the EIA's projected demand of nearly 6 Bcf/d by 2010. A terminal is on average about 1 Bcf/day: five have been approved (2 Bahamas, 2 offshore and Hackberry, LA), so can we count on 4 or 5 terminals plus the current expansions to be in place by 2010? Assume we can. That will meet a lot of annual North American demand growth, provided the price does not drop sufficiently to push those gas turbines down the merit order to intermediate service or, worse, base load. The real question is, 'where is the LNG supply going to come from?' Last year, which was an extraordinary year, spot volumes are believed to have been a bit more than 2 Bcf/d of total LNG sales. Total sales to the US were about 0.7 Bcf/d or less than US Gas exports to Mexico—so in effect, the US served as an LNG bridge to

Mexico. It would appear that the future supply of LNG to the US over the next 5 or 6 years is going to have to be bid away from other OECD economies, because the available volumes outside contracted volumes appears to us insufficient.

'Are we going to have a Global Gas Market?' If we define a global market as trade among the three regions, with choices being made based on the price difference between markets, then we have to conclude there is already a global market. Two types of arbitrage exist—Price and Logistics.

Price arbitrage has already occurred within and between basins. When prices are $7 at Boston and $3.75 in Europe, the benefits of moving a cargo to Boston are obvious (getting it there is a different matter). Last summer, the trading companies of at least two majors I have talked to, took cargoes they had planned to sell to America, but turned left in the Indian Ocean and sold them into Japan and Korea, because the price was better. As for arbitrage across the Pacific to the west coast of the U.S., that will of course have to wait until there are terminals. But price arbitrage in the Pacific is highly unlikely given the distance. Here is where we could see logistics arbitrage, or swaps. Chile or Peru-sourced LNG, contracted for South Korea, will be inclined to swap for California-bound Sakhalin or Northwest Shelf LNG: the total saving in the former case could be $1.20/MMBtu. Similarly, moving a cargo of Egyptian LNG to the US East Coast and a Trinidadian cargo to Spain involves a total transportation cost of $1.37/MMBtu. Swapping realizes a saving of more than 40 cents for the Egyptian cargo and therefore a significant profit on a cargo. But, LNG Trading is not like oil.

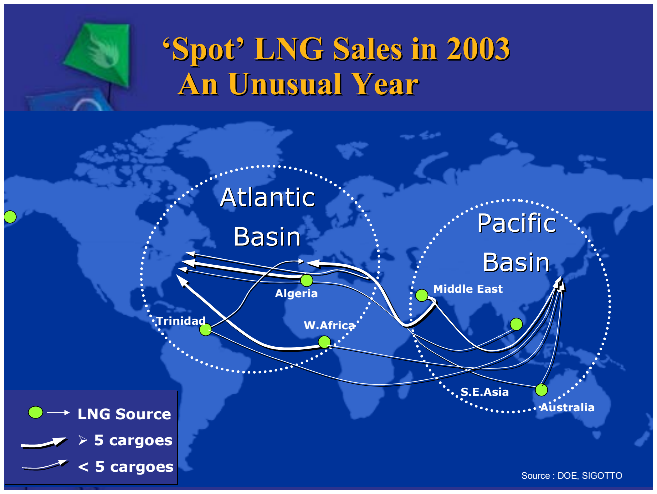
It has some complications.

- There has to be the flexibility in the contracts.
- The quality of the LNG must meet the specs for the re-gasification terminal.
- Tankers must be compatible with the Port in terms of
  - draught,
  - overhead clearance,
  - storage and
  - other capacity factors such as
    - berthing,
    - design of booms and
    - connections.

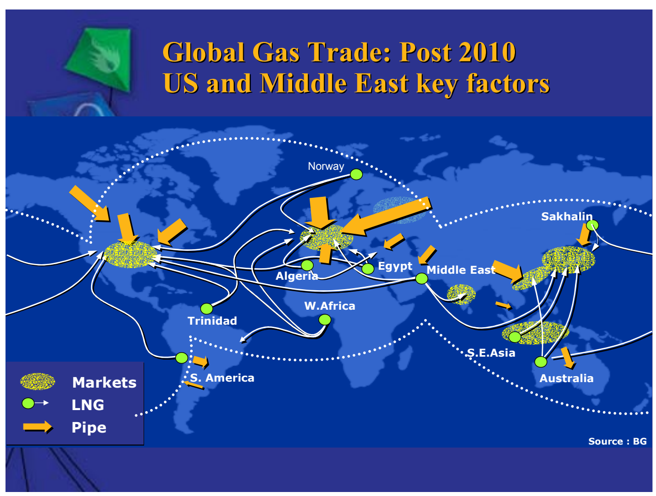
Delivering a tanker to New England because they are in a cold snap is not like delivering pizzas to someone who forgot to do their grocery shopping.

2003 was a bumper year for spot LNG trade, estimated to be about 15% or more of total LNG traded. The biggest players were the USA and Japan, for obvious reasons. Spain was also an active player importing gas to feed its growing, and competitive gas-fired power sector; Korea, is increasingly buying extra cargoes to meet its winter heating load.

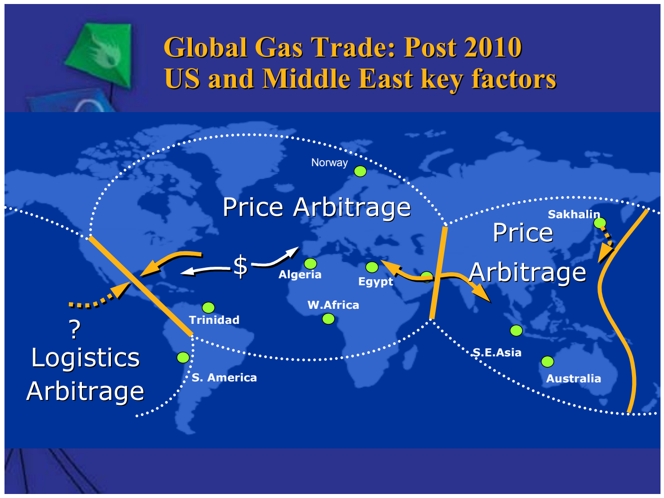
The traditional buyers in Japan and Korea are asking for flexibility in volume and in price. As contract expiries increase toward the end of the decade, there will be a lot of slop in the system. Meanwhile, I suspect, as usual the industry will over-invest in supply.



This map shows the movement of spot cargoes last year, at least as far as I can determine from the data. A problem is in the definition, since some of these are under short term contracted arrangements. Obviously, a picture over a full year suggests tankers crossing mid-ocean, but in fact this was not likely to happen in such a small club.



This map is BG's view of the world gas market in 2010, with LNG playing a key role especially from the Middle East. They see the role of the US as pivotal.



This third map is how I would summarize the market in the future: price arbitrage in the Atlantic and between the Atlantic and Pacific Basins and Logistics arbitrage wherever possible and potentially in the east Pacific. The Middle East will act like a watershed between the two major basins. Is it conceivable that some day, having scratched her ski on a rock at Lake Tahoe in February, a trader will be able to conclude that the low snow pack foretells high summer gas prices in California and arbitrage opportunities in the Atlantic Basin into the Gulf coast, thereby connecting the Basins across the North American continent?

What could alter this picture? First of all, a change in the geopolitics surrounding pipeline projects could affect the prospects for LNG—either way.

- A change of politics in the Indian sub-continent could alter the prospects for gas from the Middle East transiting Pakistan, or from Bangladesh into India. The recent election results in India may dilute such optimism but remains to be seen.
- A pipeline from eastern Russia to Japan, or through China to South Korea, while requiring huge shifts in politics, would change the outlook for LNG.
- Bolivia might get over its history with respect to Chile.
- Mexican communities might go wobbly on being a gas bridge for California.

- The mix of governments and regulatory history of the Alaskan Gas Pipeline, its treatment in the pending Energy Bill, and above all its timing could affect the economics of LNG import projects. The list goes on.

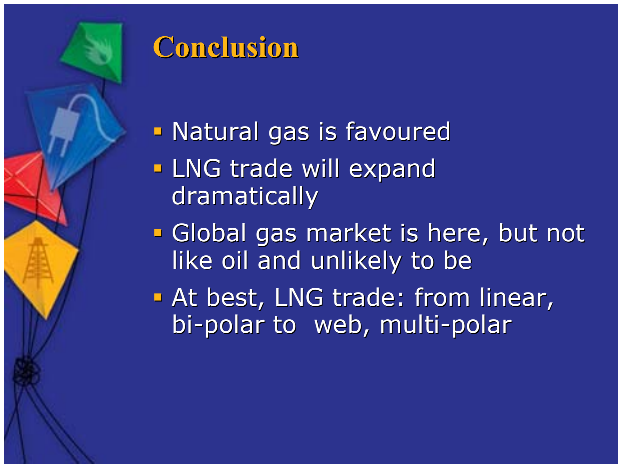
Secondly, geology can surprise as we have seen in India and Brazil with the discovery of new gas resources close to market. Domestic gas is always more appealing than imports for such countries. North America is probably the only region in the world where there is potential for gas, yet governments are prepared to forego those opportunities and import instead. That could change, but it would require Americans to realize that offshore exploration takes place elsewhere in the world without damaging the environment; it would also take a total shift in who benefits from hydrocarbon developments offshore—the Federal government or the coastal states.

Regulation of gas could change to alter the business environment. So far, regulators on both sides of the Atlantic seem prepared to give LNG terminals exemptions from Third Party Access obligations. In the current environment of tight supply or perceived tight supply, regulators are anxious to grant monopoly status.

When feeling bullish about LNG, we need to bear in mind the following check-list:

- In LNG, as in nuclear, an accident anywhere is an accident everywhere; we are already seeing the effects of the Algerian accident on planning approvals;
- The new technologies being talked about raise investment risk questions. The large tankers under design are an example: I wonder if they are not a little like trying to introduce the Hummer into the European market; or the equivalent of going back to the mainframe computer? Only 7 of 16 loading terminals and only 11 of 56 current re-gas terminals are deep enough for these large tankers, and no existing berth is yet capable of handling them. A recent call for bids on tankers specified that the tankers must be compatible with 50 existing terminals. Any technological change that tries to win position by specificity, and does not reinforce exchangeability will likely be rejected by the market.
- NIMBY is alive and well.

- Price volatility is increasing, especially with the seasonality in the North American market.
- Given that new gas supply comes from distant sources, it will be 'lumpy'; when the Alaskan gas arrives in the market, its start-up volumes will equal the capacity of 5 or 6 new LNG projects, and absorb the projected growth in the North American market for several years. The EIA's 2003 Projection of gas imports showed a 'flat spot' after 2021; its 2004 projection shows it starting around 2016; the NPC sees Alaska needed by 2013 or so. The Mackenzie Valley gas pipeline is expected before 2010; although the conventional view holds that most of its gas will be absorbed by the oil sands industry—in a continental market, that is irrelevant since it will constitute new supply to the market.
- Let's not forget that LNG is not the only source of gas (unconventional gas already makes up a major share of US gas supply);
- And, unlike for oil for mobility, gas is not the only option for generating electricity or heating homes and offices.



In conclusion:

- Yes, natural gas is the favoured fuel.
- Yes, LNG supply is growing and will continue to do so dramatically.
- We already have a global natural gas market, but it is not like either the North American gas market or the oil market and will never be like the oil market.
- At best, we should expect to see a continued shift in the structure of LNG flows from a set of closed, bi-polar shuttle systems, to an open web or a multi-polar network of flows driven by price and transportation cost arbitrage opportunities where players are simply, and quite logically, trying to optimize the movements of a very expensive manufactured good—LNG.

Thank you.