A Review and Outlook for the Global LNG Trade

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LNG offers a global commodity, i.e. a product that is fungible and can be delivered reliably to meet the growth in demand for natural gas worldwide. Concerns over security of energy supplies, higher natural gas prices, higher LNG production costs, rising gas import demand, and requirements for clean, low-emissions, flexible energy supplies continues to drive more consuming countries to develop LNG supply chains. At the same time the desire of potential new gas producers to monetize their remote, and to-date stranded, gas reserves, is continuing to diversify geographically the sources of conventional and unconventional gas supplies.

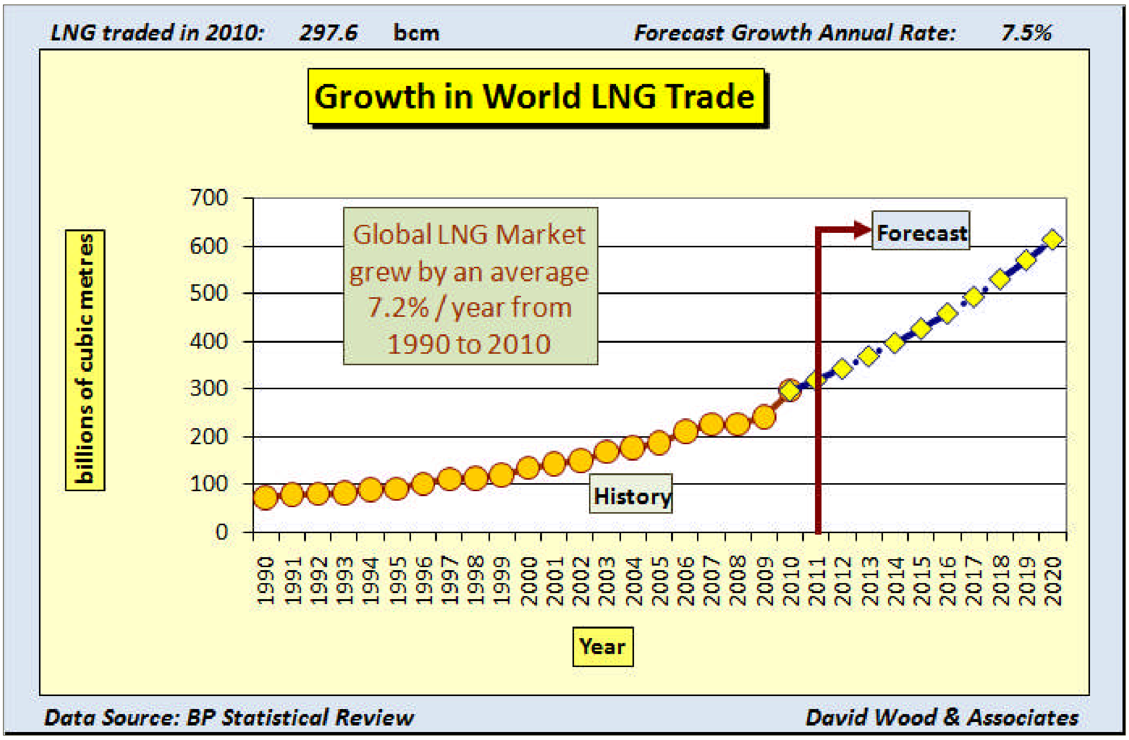

Figure 1. Evolution of the LNG trade 1990 to 2010 with a forecast to 2020

Figure 1 illustrates the growth in LNG trade from 1990 to 2010, extrapolated from 2011 to 2020. The trade evolved from 55 million tonnes per annum (mtpa – equivalent to 74 bcm of natural gas) in 1990 to 220 mtpa (298 bcm) in 2010;

representing a compound annual growth rate (cagr) of 7.2%. A review of projects now in engineering and construction, and potential projects in planning, suggest that production could reach some 320 mtpa (~430 bcm) in 2015 and some 450 mtpa (~610 bcm) by 2020 assuming a cagr for the period of 7.5% and that global LNG demand keeps pace with new installed capacity. However, forecasts for future LNG trade are difficult to predict due to: volatile regional LNG market conditions, competition from other sources of natural gas, emergence of new technologies, late development and start up of some planned projects etc. In addition, global gas demand is inextricably linked to global economic growth and persistent economic downturns can slow demand and reduce utilization of installed supply chain capacities. In the past year though a number of venerable organizations have released quite different forecasts for the role that they believe LNG will play in future gas supply. Compare for example: International Energy Agency (IEA) World Energy Outlook special report on gas (2011), Energy Information Authority of the United States (EIA) International Energy Outlook (2011), BP Energy Outlook (2011) and ExxonMobil's (2011) outlook for energy: a view to 2040. They hold differing views on how, in particular, unconventional gas developments will impact the LNG markets. ExxonMobil (2011), for example, see 15% of global gas demand being met by LNG in 2040 (compared to some 9.4% in 2010) constrained by unconventional gas developments particularly in North America and Europe.

Over the past few years many of the large oil and gas companies already involved in developing and operating longstanding LNG supply chains have taken large investment decisions to expand these facilities and have developed new projects for importing, shipping and exporting LNG. New-entrants, some much smaller companies with limited previous experience of the international gas trade have also become aware of the benefits of LNG trade and are developing new projects, some in politically-challenging countries. In such cases the new-entrant operators are relying heavily on more-experienced LNG engineering, construction companies, service providers and critical-path item suppliers to ensure the safety, engineering integrity and ultimate efficient performance of these installations. A trend toward increased competitiveness has been an increase in the economies of scale; from expansion of existing LNG receiving facilities to construction of larger liquefaction trains and ships. This trend has also led to the development of new technologies such as floating regasification, gas ports and LNG FPSOs which have emerged to compete for some important niche market positions around the World.

Higher materials and services costs and skilled manpower shortages in the LNG industry, due to the high demand of upstream and downstream oil, gas and petrochemical plants since 2004 has however reversed the trend of lower unit costs for LNG facilities developed in the 1990 to 2005. However, because of higher gas demand and persisting high gas prices in Europe and Asia, higher unit costs have slowed but far from extinguished the growth of LNG industry capacity in the period 2006 to 2011. Contracts being signed for future supplies suggest sustained growth of LNG capacity in the medium and long-term, particularly in Asia and Europe.

However, the impacts of shale gas in North America have depressed gas prices there since 2008 to the extent that imported LNG is only competitive on a small scale during seasonal peaks in demand. Indeed projects to build liquefaction plants to export LNG from Western Canada and the US are now at an advanced stage of planning. Rapid deployment of shale gas technologies to other continents outside North America seems unlikely due to the large number of wells required and reservations about the environmental sustainability of large-volume hydraulic fracture stimulation on water supplies (e.g. an outright ban on hydraulic fracturing introduced in France and several other countries tightening regulations). Nevertheless shale gas projects are seen as likely to impact some markets (e.g. China, India, South Africa, parts of Europe and South America) without displacing significantly the continued growth in LNG imports. On the Contrary, as mentioned above some organizations are forecasting a more significant impact on LNG from unconventional gas.

It is also likely that in areas where significant, relatively low-cost gas resources are present, companies and governments will look at developing integrated complexes incorporating LNG, gas-to-liquids and other gas monetization petrochemical options, following Qatar's lead. In addition, suppliers have identified the value of integration in the LNG value chain. Historically, suppliers focused attention on supplying long-term customers and building relationships that led to renewal of contracts as they approached term.

Over the past few years, greater competition, economies of scale and market liquidity have increased the importance of controlling LNG infrastructure to improve margins at every point across the value chain. Companies, such as BG, BP, GdFSuez, Petronas, QP, Shell, Statoil and Total recognized that access to markets and the ability to control infrastructure in each part of the value chain would assist them in monetizing their gas reserves and provide them with the flexibility to switch cargo destinations to access the best netbacks. Such LNG strategies have enabled these large companies to rapidly exploit evolving LNG market opportunities, while their competitors have lacked the capability to do so. Other key players in LNG supply are following their lead (e.g. ExxonMobil, Gazprom, Chevron, ENI, Repsol), but some of them have a significant gap to close on the market leaders and are regretting that they did not chose to do so much earlier.

Figure 2 highlights the growth of LNG exports and imports in the key global regions. Dominated by Asian supply in period 1990 to 2000 the LNG export industry saw rapid growth in supply from Middle East North Africa (MENA i.e., Qatar, Oman, Yemen, Egypt) and West Africa (i.e., Nigeria, Equatorial Guinea) and Latin America (i.e., Trinidad &Tobago, Peru) in the period 2000 to 2010. Further growth in non-Pacific supply is seen as coming principally from the

Africa, North America, Latin America as well as MENA regions. On the other hand rapid expansion of Pacific supply from 2014 onwards is set to come from Australia, Indonesia and Papua New Guinea based upon projects sanctioned and in planning.

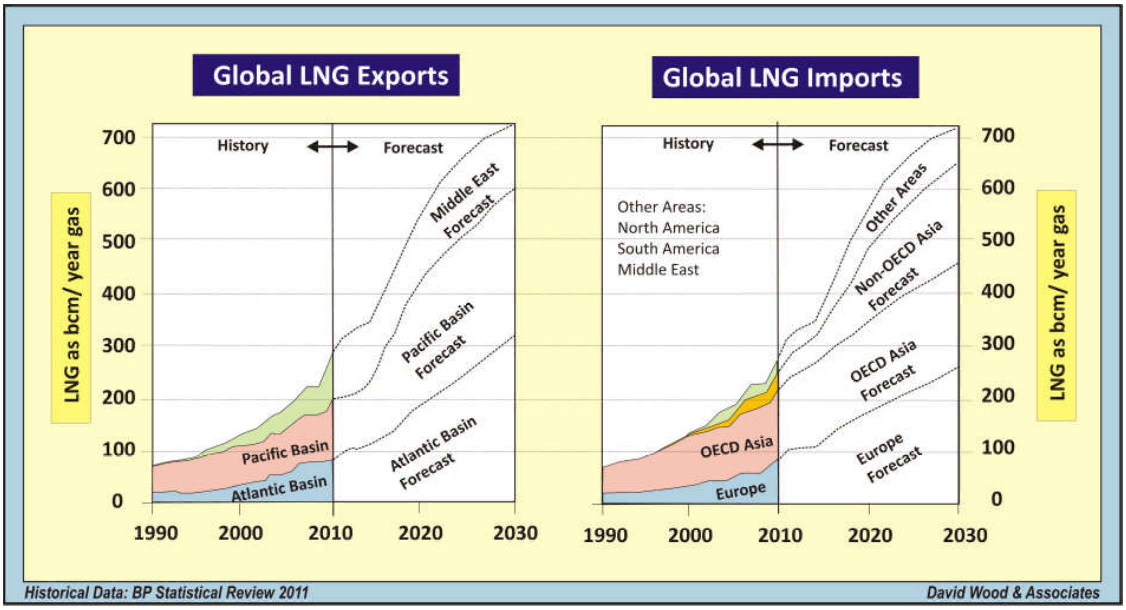

Figure 2. Historical evolution of LNG exports and imports by region (data source: BP statistical review June 2011) with forecasts (by the author) for supply and demand growth by region to 2030.

On the demand side, whereas OECD-Asia dominated the LNG destinations from 1990 to 2010, the main future growth is expected to come from Non-OECD Asia (i.e., China, India, Indonesia, Thailand and Vietnam) and Europe, where increasingly it will be able to compete with expensive and politically insecure, long-distance pipeline gas supplies.

The growth of the industry has been facilitated as much by technology breakthroughs as by market demand growth. The progressive increase in gas liquefaction train size provides one example of this (Figure 3) with train sizes increasing steadily over the past four decades. In spite of these cost obstacles the large IOCs, NOCs and technology providers in the industry continue to push the limits upwards on the size of single liquefaction trains. Several technology providers have separately in recent years presented outlines of single trains with up to 11 mtpa capacities. The technology has undergone a remarkable development in the past decade versus its 40-yr history. The development of much larger LNG carriers, e.g. the Q-max vessels (265,000 m^3 capacity) entering the market in 2008 for QP, and much larger LNG land-based containment tanks (up to 200,000 m^3) have been necessary to provide the economies of scale that can sustain large-capacity supply chains.

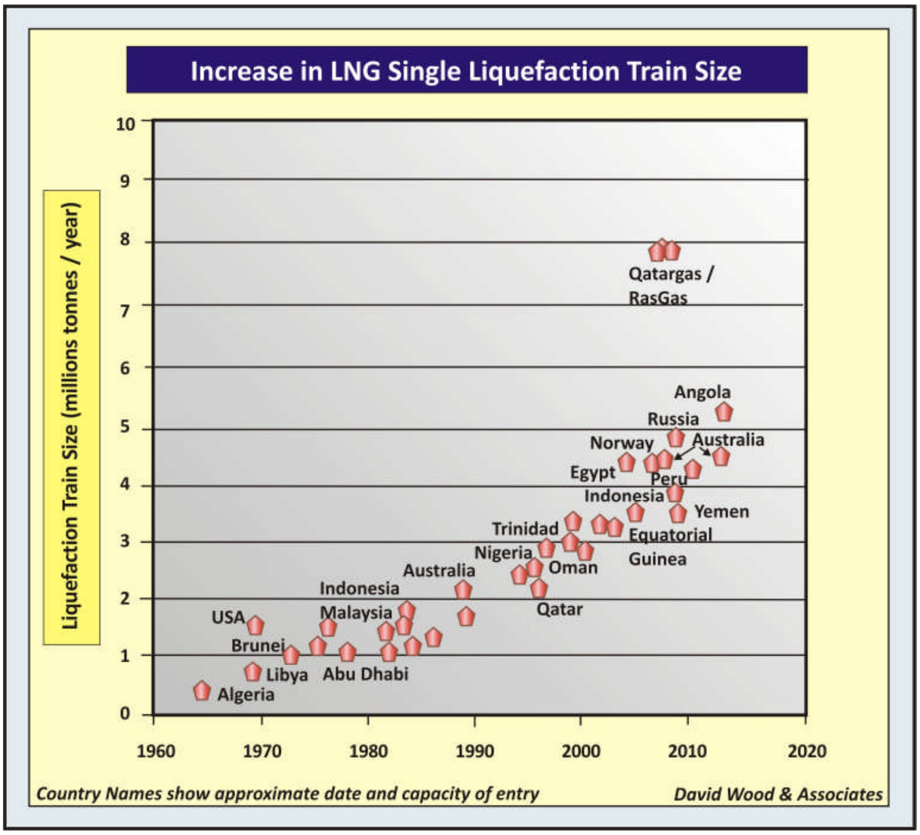

Figure 3. Evolution of gas liquefaction train size since the 1960's.

LNG Import Markets

Figures 4 to 6 compare the status of the LNG imports in various countries and regional markets in 1996 and in 2010. These two snapshots in time highlight where the key developments in demand have occurred and just how rapidly the industry has grown in some countries. Figure 4 tabulates LNG imports showing how the trade has diversified and grown almost threefold during the period. In Europe, Spain and France have established significant expansions of trade and the UK LNG demand has evolved to be the second highest in Europe over just a few recent years. In Asia, South Korea's LNG imports have grown more than threefold, whereas Japan has posted a respectable 47% growth during that period. It is though the emergence of China and India during the period that is signaling where much of the future growth is expected to come from. US LNG imports rose steadily to 21.82 bcm in 2007, but contracted to 12.23 bcm in 2010 due to shale gas competition and price collapse. Nonetheless in 2010 the US still imported ten times more LNG than it did in 1996. The LNG industry is not dead in North America, but is likely to play a more complex import-export role in the future, with exports likely to dominate in the medium term.

When the data in Figure 4 is displayed graphically in Figure 5 the true scale of expansion and diversification of the LNG industry during the period is revealed. In addition to the large market-shares dominated by the countries mentioned above, the emergence of a diverse Latin American import market is revealed, something that was not envisaged even just five years ago. Indeed Argentina, Chile and Brazil are all developing LNG infrastructure to facilitate access to secure energy supplies and promote economic growth. The LNG industry has managed to circumvent access to the politically and geographically stranded gas resources of Bolivia and introduce competitive supplies of imported gas.

Year →	1996	2010
Country ↓	Imports bcm	
USA	1.2	12.23
Canada		2.00
Argentina		1.78
Brazil		2.78
Chile		3.07
Dominican Republic		0.82
Mexico		5.72
Puerto Rico		0.77
Belgium	4.0	6.43
France	7.8	13.94
Greece		1.17
Italy		9.08
Portugal		3.01
Spain	6.9	27.54
Turkey	2.3	7.92
UK		18.67
Kuwait		2.78
UAE		0.16
China		12.80
India		12.15
Japan	63.8	93.48
South Korea	13.0	44.44
Taiwan	3.4	14.90
Global	102.4	297.6

Figure 4. LNG imports by country in 1996 and 2010. Data comes from BP statistical reviews and the colour code separates Atlantic, Middle East and Pacific market regions.

The emergence of LNG markets in some of the European countries with low gas demand (e.g. Portugal and Greece) and Italy, together with expansions in the Turkish market are likely to be followed over the next decade by new market entrants from Eastern Europe (e.g. Poland, Baltic States and some Balkan nations). In addition the Netherlands, the only net gas exporter in the European Union, commissioned its first regasification terminal in Rotterdam in 2011. It is likely that Rotterdam will become an important northwest Europe gas trading hub with pipeline gas and LNG competing for access to the large German and UK markets under a range of term and spot contracts. New LNG facilities are planned for France (e.g. EdF plans a new plant at Dunkirk sanctioned in 2011). Stagnant economic growth may slow LNG development in Europe. However, with North Sea gas in decline and EU environmental policies curtailing nuclear and coal power plant developments, even if energy demand remains flat in the region, the quantity of gas imports seems destined to increase significantly.

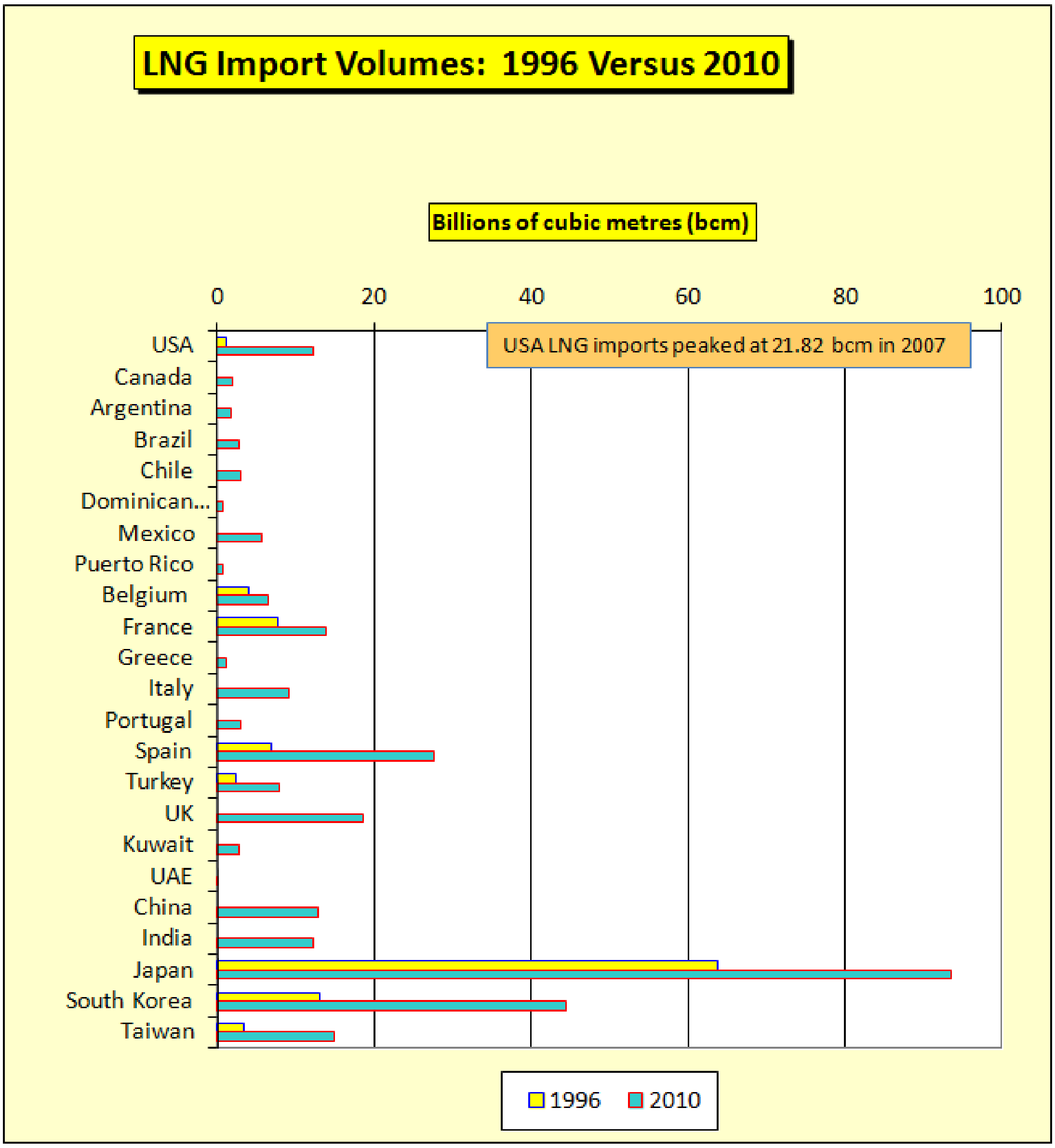

Figure 5. Graphical comparison of LNG imports by country in 1996 and 2010. Data comes from BP statistical reviews and the colour code separates Atlantic, Middle East and Pacific market regions.

The emergence of small LNG import markets in Kuwait and Dubai is testament to the versatility and flexibility of the industry, with short-term cargoes coming not from neighboring Qatar but from more competitively-priced sources around the World. More short-term spot markets such as these are destined to develop over the coming decade and will play an important role in market liquidity, diversity and competition for spot LNG cargoes. Floating storage and regasification plants that can be built and deployed rapidly have successfully targeted these markets over the past five years and succeeded in reducing regasification costs and making small-scale LNG supply chains commercially viable.

Figure 6 illustrates how the Atlantic markets have grown to take a larger share of the trade in 2010 than they did in 1996. The emergence of the small but significant niche Middle East LNG market is also illustrated. Whereas these regional markets were completely distinct and not really competing for LNG supply in the 1990's this has all changed over the interim period, particularly with rapid growth of Middle Eastern suppliers that can serve both Atlantic and Pacific markets. The usefulness of the Atlantic versus Pacific market distinction is likely to diminish over the coming decade as more and more LNG travels along diverse and lengthy supply chains around the World for long-term and short-term contracts.

LNG Imports: (bcm)	1996	2010
Atlantic Basin	22.2	116.9
Pacific Basin	80.2	177.8
Middle East	0.0	2.94

Figure 6. Pie charts and supporting data table in bcm comparing LNG imports by region in 1996 and 2010. Data comes from BP statistical reviews and country combination colour codes come from Figure 4.

Figure 7 lists the 26 countries that imported LNG in 2011 and 27 countries that are considering or in some cases undertaking the construction of new regasification facilities. In fact the list of countries planning to develop LNG import infrastructure continues to get longer year-by-year as the industry further diversifies. Clearly it will take probably the best part of the next decade before many of the countries in the right-hand column of Figure 7 actually establish operational LNG import supply chains. The Netherlands made this step in 2011 with the commissioning of its Gate LNG terminal in Rotterdam, opening up that location as a potentially important northern European gas trading hub.

There is a niche market for isolated island nations with limited overall energy demand, but limited to expensive distillate and fuel oil power generation facilities in the absence of LNG. These markets may only import two or three cargoes per year and in some cases their demand will be seasonal. Such markets individually are of little consequence to the overall LNG trade. However, collectively several island markets can be attractive, especially if they are located on or close to the main base load supply chain routes. In such cases it is possible to deliver partial spot cargoes at minimum incremental cost, or even backhaul cargoes with vessels that would otherwise be sailing back to their main loading ports essentially with just a small heel cargo to maintain the vessel's tanks at cryogenic temperatures.

Countries Importing LNG	
Situation in May 2012	
CURRENT 26	PLANNED /POSSIBLE
Argentina	Albania
Belgium	Aruba
Brazil	Bahamas
Canada	Bahrain
Chile	Bangladesh
China	Bulgaria
Dominican Republic	Croatia
Dubai	Cuba
France	Dominican Republic
Greece	El Salvador
India	Finland
Italy	Fujairah (UAE)
Japan	Germany
Kuwait	Indonesia
Mexico	Ireland
Netherlands	Israel (short-term)
Portugal	Jamaica
Puerto Rico	Jordan
South Korea	Kenya
Spain	Lebanon
Sweden	Lithuania
Taiwan	Malaysia
Thailand	New Zealand
Turkey	Pakistan
United Kingdom	Philippines
United States	Poland
	Singapore
	South Africa
	Ukraine
	Uruguay
	Vietnam

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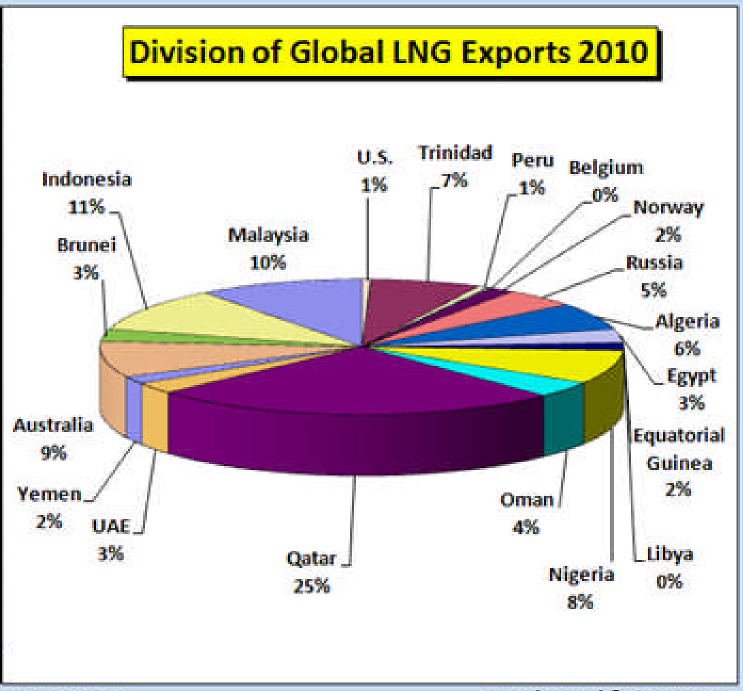
Figure 7. A list of countries that are importing LNG in 2012 or planning to at some stage in the future.

LNG Export Markets

Figure 8 summarizes LNG exports by country in 2010. The four largest LNG producers Qatar, Indonesia, Malaysia, & Australia, in that order by volume accounted for 54% of all LNG exports in 2010. In 2003 the top four exporting countries (Indonesia, Algeria Malaysia and Qatar, in that order) accounted for 63% of all LNG exports. This highlights the diversification of the LNG export markets and that some countries are increasing their share of it through massive capital investments (i.e. Qatar and Australia), while others are losing ground through much slower investment and expansion strategies, aging infrastructure and depleting reserves supplying the older plants (i.e. Algeria, Indonesia and UAE).

Hovering just below the top four exporting nations in 2010 are Trinidad and Nigeria, both expanded their capacity rapidly between 2000 and 2005 but subsequently their growth has been curtailed. In the case of Nigeria there are plenty of reserves but the problems are political unrest in the Niger Delta areas where the gas is located and unstable fiscal terms that have led potential investors to delay commitments for several years on new plants. In the case of Trinidad the problem is both limited proven gas reserves inhibiting rapid expansion by building new liquefaction trains and the rapid and significant fall in demand for imported gas in the U.S., traditionally its main and closest customer.

LNG Exports	
Country	bcm
U.S.	1.6
Trinidad	20.4
Peru	1.8
Belgium	0.6
Norway	4.7
Russia	13.4
Algeria	19.3
Egypt	9.7
Equatorial Guinea	5.2
Libya	0.3
Nigeria	23.9
Oman	11.5
Qatar	75.7
UAE	7.9
Yemen	5.5
Australia	25.4
Brunei	8.8
Indonesia	31.4
Malaysia	30.5
Global Total	**297.6**



Data Source: BP Statistical Review June 2011 *David Wood & Associates*

Figure 8. LNG exports by country 2010. Data from BP Statistical Review June 2011.

Countries to watch for future potential LNG export growth, not among those already mentioned include: Russia (expensive large arctic gas), Libya (depends upon the pace of its political and economic regeneration) and Egypt (depends upon pricing policy, political strategies and fiscal incentives it provides to investors). Bolivia, Iran, and Venezuela all have sufficient gas reserves to justify gas liquefaction exports, but political isolation and lack of access to state-of-the art technologies and capital markets will make it difficult for these countries to develop functioning LNG export supply chains in the next decade, unless there is a significant change in their gas management, political alliances and investment strategies.

Countries Producing & Exporting LNG

Situation in May 2012

CURRENT 19	PLANNED / POSSIBLE
Angola (Started June 2012)	Azerbaijan / Georgia?
Abu Dhabi	Bolivia (opposed by government?)
Algeria	Brazil? (not for several years)
Australia	Cameroon (GdFSuez in planning)
Brunei	Canada (British Colombia)
Egypt	Cyprus
Equatorial Guinea	Iran (delayed again?)
Indonesia	Iraq (Shell?)
Libya	Israel
Malaysia	Mozambique (planning)
Nigeria	Papua New Guinea (Construction)
Norway	Tanzania (planning)
Oman	United States (Alaska, Gulf of Mexico, Oregon)
Peru	Venezuela (delayed again?)
Russia	
Qatar	
Trinidad and Tobago	
United States (Alaska)	
Yemen	

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Figure 9. A list of countries that are exporting LNG in 2012 or planning to at some stage in the future.

Figure 9 lists the 18 countries that are exporting LNG in 2011 and 11 countries that are considering or in some cases undertaking the construction of new liquefaction facilities. Angola is likely to be the first country in the right-hand list to commission a new facility over the next year or so. Papua New Guinea has one project under construction led by Exxon Mobil.

The U.S. has several Gulf of Mexico projects looking to liquefy and export shale gas as LNG from terminals built solely as receiving terminals, but probably will not commission these until about 2015 or 2016. One of these, Sabine Pass Liquefaction led by Cheniere Energy, entered into four long-term customer sale and purchase agreements (SPA) for 16.0 mtpa of LNG and received U.S. Federal Energy Regulatory Commission (FERC) approval in early 2012. This places ahead of rival projects. Significant opposition exists from some quarters in the United States that is likely to delay the progress of some of the proposed export projects and perhaps ultimately place a cap on how much gas is allowed to be exported. Three Kitimat liquefaction projects are progressing on the West Coast of Canada, led separately by Apache, Shell and BC LNG, a privately held 13-member co-operative involving Haisla First Nation indigenous community. These projects are all planning to export shale gas as LNG to Asian markets and have Asian buyers on board. The Kitimat projects also involve supply gas pipelines across the Rocky Mountains and are expected to start exports about 4 years after the final investment decision is made.

Alaska, which has expended much effort over the past 5 years trying to secure investment into a gas pipeline to the Lower-48 US market, finally admitted defeat on that project in May 2012 when it officially endorsed the switching of attention to a LNG export project with a liquefaction plant to be located in Valdez. The project including a trans-Alaska gas pipeline is expected to cost between US$30 billion and US$40 billion, is at its early stages of planning with gas-holders ExxonMobil, BP and ConocoPhillips supporting it, but with many fiscal and regulatory hurdles yet to be overcome. To be commercially viable the project would need to be of high capacity (i.e. >10 mtpa) and likely require sales prices significantly in excess of current U.S. Henry Hub gas prices plus the cost of liquefaction.

Some uncertainty exists surrounding LNG price indexation for North American LNG export projects; will prices be referenced to crude oil prices (the traditional Asian model), North American gas hub prices, or more likely a combination of the two? Cheniere Energy for its Sabine Pass project in Louisiana, which is expected to make a positive final investment decision in 2012 or 2013, is believed to have agreed the sale of LNG to its SPA customers at about 115% of the U.S. Henry Hub gas price, in addition to fixed liquefaction process costs, which are likely to be in the vicinity of US$2.5/ mmbtu to US$3.0 /mmbtu for that project.

Shell’s associated gas gathering project in Southern Iraq, finally signed in 2011 after long negotiations, is also likely to involve a gas liquefaction plant, but this is not likely to be ready before 2017 at the earliest.

A series of recent, large deepwater gas discoveries offshore Mozambique by Anadarko, ENI and their partners and offshore Tanzania by BG Group and its partners seems to hold the necessary gas reserves to justify a gas liquefaction project. Pre-FEED studies commenced on these discoveries in mid-2011, but LNG export projects fed by this newly found gas are unlikely to be operational, if sanctioned, by 2016 at the earliest.

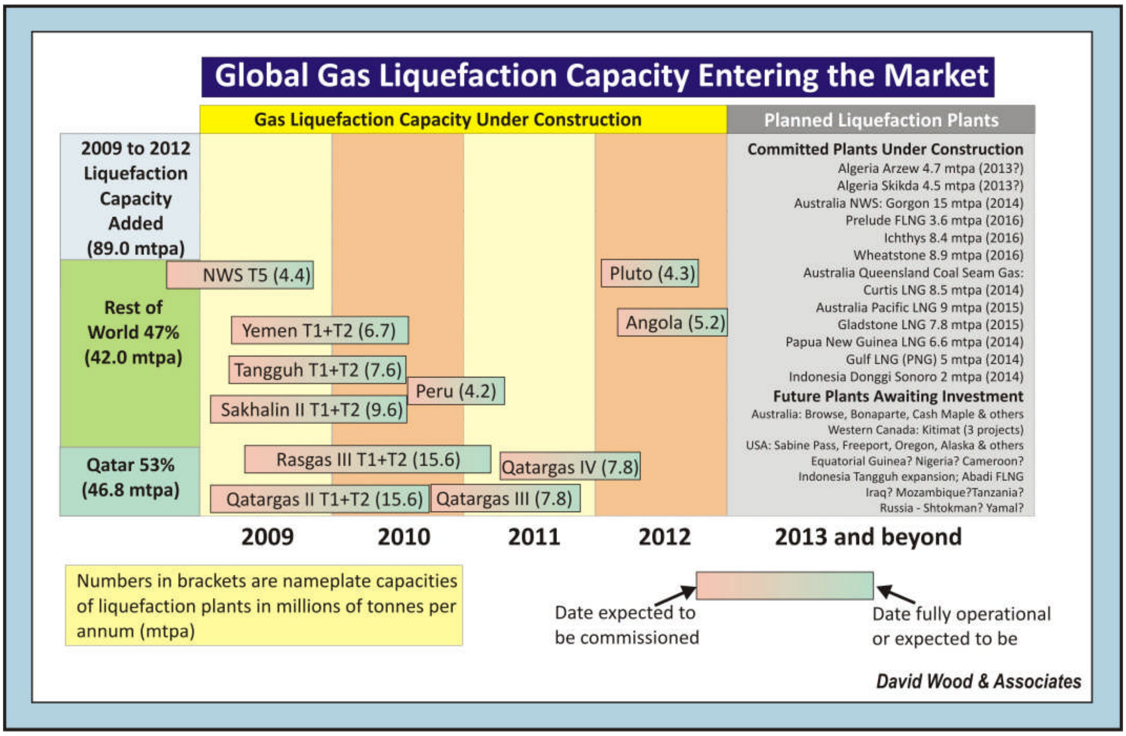

Figure 10. Gas liquefaction projects onstream in the 2009 to 2012 period and some of the projects under planning and development for 2013 and beyond

Figure 10 shows that of the 98 mtpa of capacity scheduled to come onstream in the 2009 to 2012 period almost half of it is has been located in Qatar. The big 7.8 mtpa trains associated with expansions of the Qatargas and Rasgas projects have dominated new capacity coming online over the past three years. These new plants are consolidating Qatar's position as the World's premier LNG supplier, but several of the new liquefaction trains had to divert cargoes originally destined for the U.S. market to Asia and Europe, because of the U.S. gas price collapse. Asia and Europe have so far been more than able to absorb this unexpected additional capacity. Japan's increase in LNG demand following the Fukushima nuclear disaster and subsequent shutdown of most of Japan's nuclear power capacity during 2011 and 2012 has substantially boosted Asia LNG demand.

Other notable new liquefaction projects to come onstream since 2009 include Sakhalin (Russia), Balhaf (Yemen), Melchorita (Peru) and Tangguh (Indonesia) which have all added diversification to LNG supply. The new plant in Soyo Angola came onstream in June 2012. The delayed and over-budget Pluto plant on the northwest shelf of Australia came onstream in April 2012. New trains for two old plants in Algeria being developed by state company Sonatrach on its own without the involvement of the major IOCs are reported to be delayed and may not enter the market until 2013 at the earliest.

The right-hand list in Figure 10 of gas liquefaction projects to come onstream from 2013 and beyond emphasizes the major role that Australia and North America are playing in current capital investment commitments and plans for new gas liquefaction projects. There are several projects from the northwest shelf and also several projects involving coal seam gas supplies in Queensland that have passed their final investment decisions with detailed design, engineering and construction underway. Some LNG buyers are attracted to Australian and North American supply because it is outside the influence of the Gas Exporting Countries Forum (GECF - http://www.gecforum.org/). Asian utilities in particular have shown much enthusiasm to both sanction and join relatively high-cost Australian liquefaction projects, and to buy LNG from them under long-term oil-indexed price contracts (e.g. Tepco of Japan joined in May 2012 as an equity partner the 8.9 mtpa Wheatstone project sanctioned by Chevron in September 2011, with Tohoku Electric also agreeing to buy LNG from that project in May 2012; Inpex of Japan, in January 2012, took a positive final investment decision on the 8.4 mtpa Ichthys liquefaction project to be located in Darwin and also took a 17.5% equity share in Shell's Prelude floating liquefaction project in March 2012).

It is instructive to contrast government policy in Australia with many of the GECF LNG producing nations. Australia offers IOCs and gas customers a number of advantages, including: access to major reserves, relatively benign construction environments and favorably investment and fiscal regimes. Contrast this with the tough fiscal regimes, high state-company involvement, significant domestic supply obligations at subsidized prices and requirements to support subsidized or sub-commercial investments in domestic power and /or petrochemical projects associated with liquefaction export projects in countries such as Algeria, Egypt, Nigeria, Russia and Qatar. Couple this with political instability in these countries and it is not surprising that LNG consumers and IOC investors are increasingly more attracted to invest in liquefaction projects in Australia and North America.

The large number of liquefaction projects under construction in Australia have boosted employment and investment in that country and offer to boost Australia's economy further as well as raise large fiscal revenues. However, many of these projects are experiencing cost inflation, skills shortages and community issues (e.g. Leather & Wood, 2012) that are adding to costs and leading to their capital budgets being breached. In May 2012 the 8.5 mtpa Queensland Curtis LNG project in Australia led by BG Group raised its budget to US $20.4bn from an original estimated cost of US$15bn when the project was sanctioned in November 2010. BG attributed the 36% cost hike to the appreciation of the

Australian dollar by around 20%, a related jump in labour and raw materials costs, and tougher regulatory requirements.

Liquefaction projects built and commissioned over the past 5 years have ranged in unit capital costs for the liquefaction plants (i.e. excluding upstream and pipeline costs) from about US$600 / tonne of LNG capacity to US$1600 / tonne of LNG capacity, but some of the Australian coal seam gas to LNG projects are now pushing the upper end of that range higher. Taking some 52 mmbtu per tonne of LNG (note the energy content per unit mass of LNG varies according to its composition) the capital cost for liquefaction plants currently lies within the range US$11/mmbtu of capacity and US$30/ mmbtu of capacity. Amortising those capital costs over the life of projects and taking into account upstream development and operating costs and liquefaction plant operating costs, the cost of supply at the point of loading (i.e. ex-liquefaction plant) generally falls within the range $2.5/mmbtu and $5.5/mmbtu. However, some projects with long upstream pipeline supply requirements (e.g. Alaska Valdez, Kitimat and Queensland projects) are likely to have higher costs of supply.

An Emerging Niche Market for Floating Liquefaction Plants

Shell's Prelude project offshore northwest shelf is novel because it involves a large floating liquefaction plant. From bow to stern, Shell's FLNG facility will be 488 meters long, and will be the largest floating offshore facility in the world. When fully equipped and with its storage tanks full (expected 2016), the FLNG will weigh around 600,000 tonnes. Prelude is expected to produce at least 5.3 mtpa of liquids, comprising 3.6 mtpa of LNG, 1.3 mtpa of condensate and 0.4 mtpa of liquefied petroleum gas. The FLNG facility will stay permanently moored at the Prelude gas field for 25 years. The project is owned 100% by Shell and is to involve its own dual mixed refrigerant liquefaction technology as well as many other novel offshore engineering concepts. The industry is watching the Prelude project closely to see if it offers a cost-effective solution to large remote offshore gas fields. A smaller scale FLNG is also being contemplated as part of the Gulf LNG project being planned offshore Papua New Guinea and other FLNG projects are under consideration offshore Indonesia, Australia and potentially Brazil. In the case of Brazil LNG is being considered as an option to handle associated gas produced from large remote offshore oil fields and minimize gas flaring.

In May 2012 Excelerate Energy announced plans for its Lavaca Bay FLNG project for the Texas Gulf Coast with 3 mtpa capacity, 250,000 m3 storage with a FEED study underway to bring a Floating Liquefaction Storage Offloading vessel (FLSO) onstream there in 2017 (i.e. 44 months from a final investment decision). These FLNG projects have the potential to open up a whole new dimension to LNG export markets. The industry is watching developments in FLNG projects closely, particularly the costs to deliver such projects and the operating efficiencies that such vessels can achieve. There is much uncertainty and FLNG is likely to remain a niche sector of the LNG market until it can prove its cost and efficiency credentials.

LNG's Role in European Union Gas Supply

Some large scale infrastructure projects (pipeline and LNG) have been developed for the EU gas market in recent years (e.g. the Nord Stream gas pipeline from Russia to Germany came onstream in 2011, the South Hook and Grain LNG terminals in the U.K. have expanded capacity in the past two years, the large Gate LNG terminal in Rotterdam also came onstream late in 2011). These projects suggest that LNG and pipeline gas are to compete head to head to supply key European gas customers. In fact there are now two gas prices in Europe a long-term primary oil-indexed price in continental Europe and a short-term hub-gas indexed price in UK (NBP), Zeebrugge and Netherlands (TTF). The lower gas-hub short-term prices (Figure 11) since 2008 (Platts, 2011) have caused many European gas utilities to try and renegotiate the price indexation of their long-term gas contracts, particularly with Gazprom of Russia; a move that Gazprom has resisted, which has consequently increased the competitiveness of short-term LNG across the continent. The gap between long-term pipeline and short-term LNG prices continued to widen in 2012 with several German utilities (e.g. E.On and RWE) reporting large losses in fiscal year 2011 as a consequence.

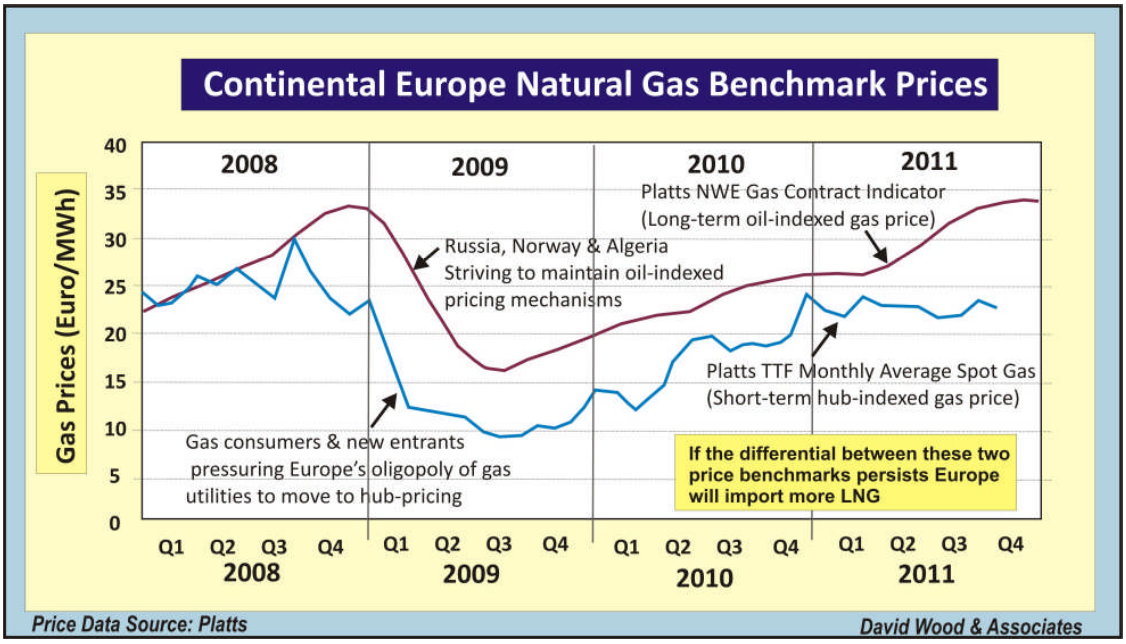

Figure 11. Europe's Long-term and Short-term Natural Gas Prices have Diverged Since 2008. (Source: Platts Nov 2011).

Figure 11 highlights that from 2008 to 2011 the spot-traded gas price has been at a substantial discount to the long-term, oil-indexed gas contract price. Platts (2011) reported that this has led to major losses for German gas importers who bought their gas at oil-linked levels, but were forced by competition downstream to charge their own customers lower spot market levels. E.ON Ruhrgas, for example, announced losses in excess of one billion Euros on global gas sales in 2011.

This competition explains to some extent why gas prices are lower in Europe than in Asia, which lacks competition to LNG from pipelines, except in China and Thailand. Where pipelines do exist in China the transit distances are so long that tariffs to move gas such long distances through the pipelines generally exceed the landed costs of LNG.

The European Union is a rapidly growing gas import market, in which LNG is destined to play a key role in gas trading. Figures 12 and 13 illustrate just how fast that market is changing by comparing the supply positions in 2003 and 2010. This information highlights the decline of indigenous EU gas production and the ongoing diversification of gas imports. Gas imports into the EU grew in absolute terms by some 37% to EU-27 from 2003 to 2010 (from 241.7 bcm to 330.5 bcm). Gas imports contribution to overall consumption in the European Union increased from some 52% in 2003 to some 65% in 2010 (Figure 12).

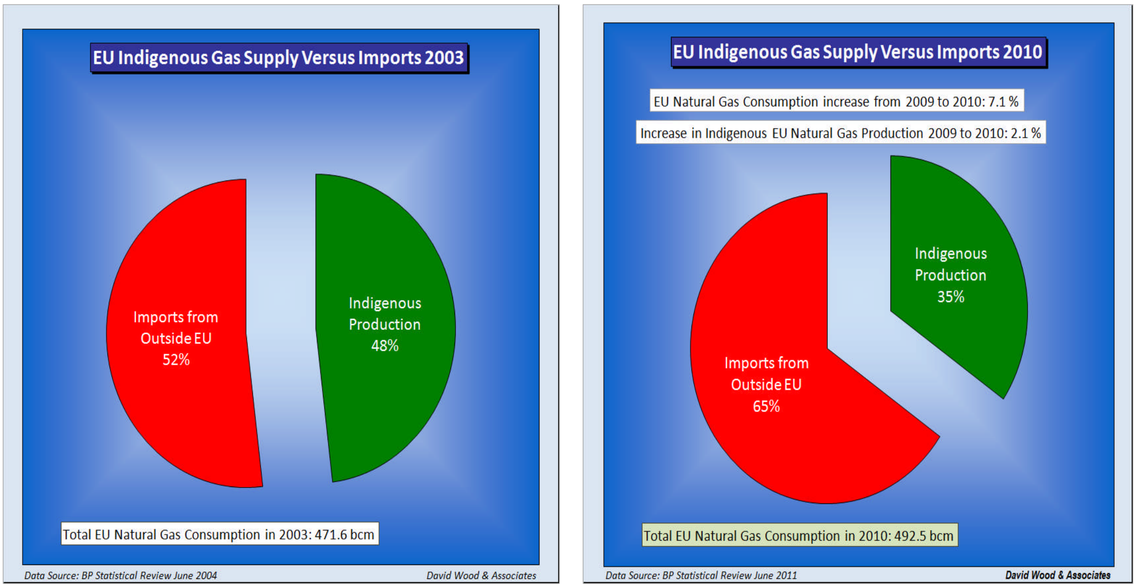

Figure 12. EU gas imports versus indigenous gas production. Data from the BP Statistical Review 2011 and 2004.

The EU is becoming rapidly more dependent on imported natural gas. Gas supply to the EU-27 countries is changing more rapidly than is often realized. Figure 13 illustrates that between 2003 and 2010 LNG's share of gas imports to the EU grew from 14.5% in 2003 to 24.1% in 2010. The LNG supply base also diversified significantly during that period.

Imported Gas supply to EU27 was ~76% by pipeline in 2010 (versus ~86% in 2003). EU indigenous production declined at an average rate of 3.5% pa from 2003 to 2010, whereas EU gas consumption increased at an average rate of 6.2% pa from 2003 to 2010. Pipeline gas supply still clearly dominates over LNG with supply from Russia and Norway constituting the major share of pipeline gas supply. It is the security of supply issues, particularly surrounding the perception that it is risky and ill-advised to become too dependent on Russian gas, that have prompted this rapid diversification of LNG suppliers.

Gas Imports to EU 27 (2003)

NON-EU Gas Suppliers	Imports bcm	Percentage Share
Russia [Pipeline]	107.56	44.50%
Norway[Pipeline]	68.37	28.29%
Algeria [Pipeline]	30.79	12.74%
Algeria [LNG]	22.40	9.27%
Nigeria [LNG]	9.24	3.82%
Qatar [LNG]	1.87	0.77%
Libya [LNG]	0.75	0.31%
Oman [LNG]	0.32	0.13%
UAE [LNG]	0.24	0.10%
Australia [LNG]	0.08	0.03%
Trinidad [LNG]	0.08	0.03%
Total	**241.70**	**100%**
LNG / Total (%)	**34.98**	**14.5%**

Source: BP Statistical Review June 2004 *David Wood*

Natural Gas Imports to EU 27 & Turkey (2010)

NON-EU Gas Suppliers	Imports bcm	Percentage Share
Russia [Pipeline]	110.71	33.50%
Norway[Pipeline]	95.88	29.01%
Algeria [Pipeline]	34.73	10.51%
Libya [Pipeline]	9.41	2.85%
Other {Pipeline]	0.00	0.00%
Algeria [LNG]	15.19	4.60%
Nigeria [LNG]	14.65	4.43%
Norway[LNG]	3.38	1.02%
Equatorial Guinea [LNG]	0.12	0.04%
Egypt [LNG]	4.44	1.34%
Qatar [LNG]	33.92	10.26%
Trinidad [LNG]	5.96	1.80%
Oman [LNG]	0.17	0.05%
Libya [LNG]	0.34	0.10%
United States [LNG]	0.35	0.11%
Peru [LNG]	0.71	0.21%
Yemen [LNG]	0.52	0.16%
Total EU Imports	**330.48**	**100.00%**
Turkey Imports [LNG]	7.92	add
Turkey Imports [Pipeline]	28.76	add
Total EU plus Turkey	**367.16**	**111.10%**
LNG / Total EU Imports (%)	**79.75**	**24.1%**
LNG / Total EU plus Turkey (%)	**87.67**	**23.9%**

Source: BP Statistical Review June 2011 *David Wood*

Figure 13. EU gas imports versus distinguished as pipeline and LNG from exporting country sources. Data from BP Statistical Review 2011 and 2004.

Figure 14 identifies that a step change occurred in EU LNG imports in 1999 with more liquefaction capacity coming on line in the Atlantic Basin (i.e., from Nigeria, Trinidad, etc). Another step change occurred when Qatargas II started exports to Europe in 2008. As a good deal of LNG entering Europe is now traded against natural gas benchmarks (i.e. NBP in the UK, TTF in Netherlands, Zeebrugge in Belgium) in theory independent of oil prices. In times of high oil prices, to which a good deal of long-term gas pipeline contracts to Europe are indexed, at least in part, gas-benchmarked LNG is very cost competitive. Hence, in the past two years or so LNG from around the World has displaced some expensive pipeline gas. This has placed some gas and power utilities in Europe in financial difficulties as they have long-term take-or-pay contracts for Russian gas for which they are paying high prices than gas is trading at the short-term European gas hubs.

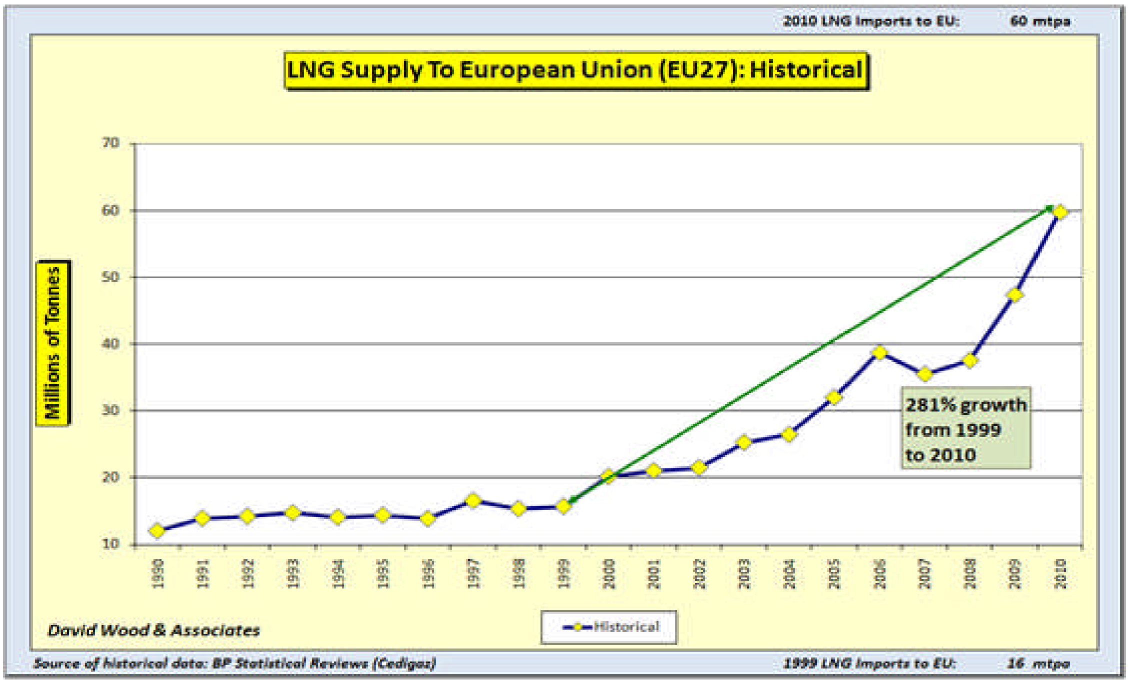

Figure 14. Historical trend of EU LNG imports showing rapid growth over the past decade. Data from BP Statistical Reviews.

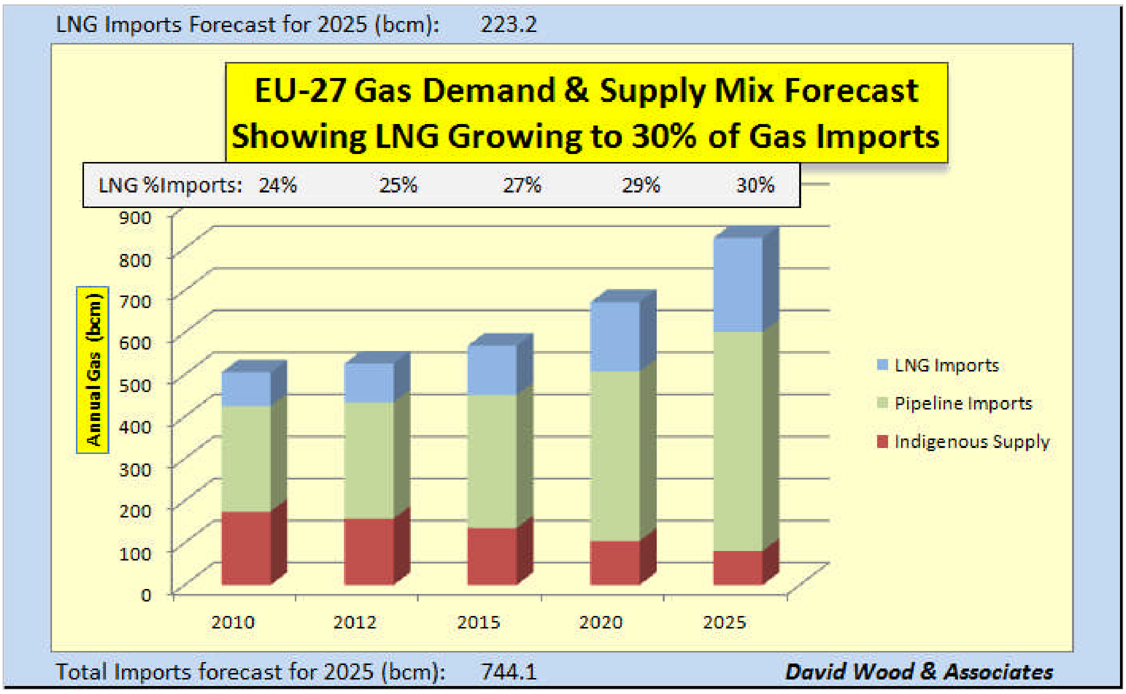

Figure 15. Gas supply forecast for LNG, pipeline and indigenous supply sources to the EU from 2010 to 2025.

Figure 15 presents an optimistic forecast of how LNG might contribute to the EU gas market over the period 2010 to 2025. This forecast assumes 3.5% cagr gas demand growth and 5.0% per annum decline in indigenous gas supply leading to about a 5.6% cagr in total EU gas imports. Assumptions associated with EU gas demand growth and decline in indigenous supply are only part of the story. Gas price indexation and contract differences between LNG and pipeline are also likely to play a role, as are costs. If LNG supply costs increase substantially versus long-distance pipeline gas tariffs then LNG would struggle to grow its share of the market. However, such concerns are more than offset by the increased uptake of renewable energy sources across Europe with a declining appetite for coal and nuclear (e.g. post-Fukushima response from Germany to phase out its nuclear capacity), which both favour more rapid uptake of gas in the medium-term. The forecast in Figure 15 also reflects the significant distrust among many European gas consumers of Russia as a reliable gas supplier in the long term should also result in a greater share of gas imports to Europe coming from a diversified group of more reliable LNG suppliers. However, two complicating short-term factors exist that pose potential problems for LNG supply into Europe:

1) the LNG price differentials between Asia and Europe have in recent years drawn short-term cargoes to be diverted or re-directed from European destinations to Asian markets. This has security of supply issues for Europe, particular for the high seasonal demand driven by cold snaps in the European winer. In recent years stagnant economic growth has meant European gas demand has not significantly exceeded LNG supply. However, countries like the U.K. that have become increasingly dependent on imported gas, are unable to rely on securing short-term LNG cargoes when needed without the risk of paying very high prices for them to compete with the currently higher-priced Asian markets.
2) The unprofitable nature of gas in the short-term for those EU utilities locked into long-term oil-indexed gas supply contracts with Russia make those utilities unwilling to sanction new gas-fired power projects or to expand their gas consumption. Hence in 2011 and 2012 due to European economic recession and pricing issues the natural gas market has shrunk rather than grown in some European markets (e.g. Germany). On the other hand consumption of coal for power generation has grown in these markets which is contrary to medium-term and long-term expectations.

Based upon the assumptions made LNG should be expected to reach 30% of EU gas imports between 2020 and 2025. The absolute magnitude of those imports will depends to a degree on the level of economic recovery and growth Europe is able to achieve over the next decade. The impact of major gas pipeline projects planned from Middle East and Caspian country suppliers into southeastern Europe (e.g. Trans-Anatolian Pipeline project from Azerbaijan through Turkey) could limit expansion of LNG supplies. However, geopolitical issues and conflicts along such routes suggest that the EU is unlikely to become dependent on such high-risk pipeline-based supply chains. The dilemma for the EU is that it must invest large amounts of capital in both new pipeline and LNG supply chains. The economic recession has slowed down such investments, but there is a risk in delaying the building of this infrastructure that gas suppliers may redirect their gas to more lucrative LNG markets in Asia leaving the EU with a gas supply shortfall in the next five years if indigenous gas supplies decline more rapidly than forecast. The recent discovery of large gas deposits in deep waters of the Eastern Mediterranean, offshore Cyprus and Israel, are new sources of gas that are likely to be developed for gas liquefaction export projects and compete with proposed Caspian and Middle East gas pipeline routes to Europe. Political tensions between Turkey, Cyprus (Greece) and Israel have risen since this new gas has been discovered. Such tensions will likely delay the development of both LNG and pipeline routes crossing this region. However, the proposed East Mediterranean LNG projects should in the medium term improve the EU's security and diversity of gas supply.

In conclusion the evolution of global and regional LNG trade over the past twenty years has been a story of rapid growth, diversification and increased flexibility in LNG cargo movements. The LNG trade continues to be dominated by long-term sales contracts, despite growing and significant short-term (spot) and medium-term supply agreements. This is because liquefaction projects require tens of billions of dollars of finance to build and financial institutions and equity investors require secure long-term offtake agreements to justify such investments. This is unlikely to change over the next decade with the short-term trade continuing to represent less than 20% of overall LNG supply. Nevertheless, the spot LNG market is likely to expand its influence on gas prices in regional markets, helping to moderate them in times of peak demand.

Asia continues to dominate global LNG trade, but the European LNG market has evolved significantly in the past decade and seems destined for sustained growth and diversification over the next decade or so. The promising expansion of LNG imports to the United States up to 2007 proved to be a false dawn due to indigenous shale gas production causing gas price collapse. However, North America is likely to play a more complex role in global LNG trade with some terminals both importing and exporting LNG depending upon market conditions. It remains to be seen how such terminals will compete with already established supply chains to Europe and Asia and how it will influence gas prices and price indexation in those markets. Many gas consumers in those regions are expecting, over the course of the next decade, continued diversification of LNG supply from new sources (e.g. North America, East Africa and East

Mediterranean) to improve security of supply and bring down the delivered price of LNG into their respective markets.

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