PROSPECTS FOR LNG TO CONTRIBUTE TO THE "20-20-20" TARGETS AS A TRANSITION FUEL

John Holding
Independent Practitioner
(Energy Macroeconomics)

ABSTRACT

Given the EU targets – endorsed in March 2007 by EU leaders – which are to be met by 2020:

- A reduction in EU greenhouse gas emissions of at least 20% below 1990 levels
- 20% of EU energy consumption to come from renewable resources
- A 20% reduction in primary energy use compared with projected levels, to be achieved by improving energy efficiency

– collectively known as the "20-20-20" targets – a question that naturally arises is whether there is a role for LNG (Liquefied Natural Gas) as a transition fuel, or even as a component of the ultimate solution.

LNG as a globally transportable, fungible fuel offers the same attributes as natural gas with the added advantage of freeing the dependence from established fixed gas pipeline supplies – e.g. Russian gas into Europe. But gas is a hydrocarbon, so it contributes to GHGs, however, it is relatively "clean" having the lowest Carbon Coefficient of all naturally occurring hydrocarbons. Consequently there are numerous opportunities for gas, hence LNG, to substitute for dirtier fuels. It appears that LNG could contribute towards the EU targets.

But at the present time, global LNG projects are undergoing a hiatus – for a whole raft of reasons. The US market for LNG has currently shrunk with the exploitation of unconventional US Shale Gas resources and this additional supply source has contributed to the fall in Henry Hub prices thereby impacting the Atlantic Basin LNG market equilibrium price, hence supply-side economics.

The paper will look over these issues to weigh and balance them along with considerations of the UK and European state of play with respect to LNG projects and markets and the apparent bonanza of US Shale Gas. LNG's role in a carbon constrained world will be evaluated, particularly from the point of view of IOCs (international oil companies) who will be driven by the outlook for risks and returns in the hugely capital intensive and long term LNG business.

The paper will conclude by drawing some conclusions as to the viability of LNG as a transition fuel to contribute to the 20-20-20 targets.

Keywords: LNG, Natural gas, 20-20-20 targets.

INTRODUCTION

The relatively recent convergence of energy issues and concerns over climate change (as distinct from concerns over *air pollution* caused by, for example, sulphur dioxide emissions from coal fired power stations or exhaust fumes from diesel engined vehicles) is demonstrated by pronouncements from governments and NGOs at all levels identifying global warming as the threat that brings together the underlying issues related to greenhouse gases (CO_2 emissions specifically) – hence carbon, hence the continued use of fossil fuels. Developed and developing nations require energy for comfort, convenience and to drive economic growth but the attendant atmospheric emissions from the combustion of fossil fuels present a conundrum that governments are wrestling with since the Kyoto Protocol was adopted in December 1997[1].

On the face of it, Liquefied Natural Gas (LNG) – being a pure fossil fuel – might command only a limited place as an energy source in a low carbon economy, yet LNG, and natural gas itself, have shown themselves to be quietly resilient in the energy roller coaster of the last 40 years despite being buffeted by shifting government policies and industry uncertainties – natural gas finding favour at times and being shunned at others.

This paper will consider both the EU and the UK energy and climate change policies with respect to LNG's future prospects and the competitive environment for primary energy. The specific topic we are concerned with here is the first of the "20-20-20" targets i.e. the prospects for LNG to contribute to a reduction in EU greenhouse gas emissions of at least 20% below 1990 levels by 2020.

In examining the roles for governments and markets we will scrutinize the evidence that supports and detracts from LNG's place as a primary fossil fuel energy source and consider its relevance in the transition to a low carbon economy.

[1] The Kyoto Protocol entered into force in February 2005 for the Annex 1 Parties

SECTION ONE: POLICIES AND TARGETS

(1.1) THE EU'S "20-20-20" TARGETS IN CONTEXT

The EU's "20-20-20" targets, *viz.* –

- A reduction in EU greenhouse gas emissions of at least 20%[2] below 1990 levels
- 20% of EU energy consumption to come from renewable resources
- A 20% reduction in primary energy use compared with projected levels, to be achieved by improving energy efficiency

– were endorsed by EU leaders in March 2007 leading to a climate and energy package which was agreed by the European Parliament and Council in December 2008 and became law in June 2009.

Previously, EU energy efforts have been dominated by concerns over security of supply and development of infrastructure, progressing to the issue of the Green Paper in March 2006 "A European Strategy for Sustainable, Competitive and Secure Energy" which was the forerunner to the current legislation.

With respect to gas supply specifically, in July 2009 the Commission published a proposal for a new regulation – which would replace the Directive of April 2004 on the same topic – to strengthen the principles already laid down in order to assure greater coordination throughout the European Union. It was noted in the communiqué that gas accounts for more than one quarter of energy supply in the EU, over half of which is imported from external sources (of that, Russia provided 42%). By 2020, over 80% of EU gas is likely to be imported. In June 2010 the Spanish Presidency announced that an agreement had been reached with the European Parliament's Industry Committee on draft legislation which lays down new requirements for plans to offset any serious disruptions to gas supplies from third countries.

However, the deliberations of EU policy evolution have been impacted by external events; the generally uninspiring Copenhagen Accord, together with the global economic downturn and continual concerns with East-West gas flows, stimulated calls in April 2010 by several European academics to conduct a full rethink of EU energy policy. "A Smart EU Energy Policy"[3] contained concrete recommendations for policy changes and indicated that the 20-20-20 targets are not robust enough, particularly to support the long term investments necessary in the energy sector. At about the same time the European Climate Foundation (ECF) – an NGO concerned about Europe's GHG emissions – issued their "Roadmap 2050" which purported to show that the transition to a low carbon Europe (i.e. 80% GHG emissions reductions) by 2050 is both technically and economically feasible. The study also provided concrete policy recommendations.

Whether directly reacting to the above developments or otherwise, in July 2010 the European Commission warned that 'the uncertainty created by the [ongoing economic] crisis puts the brakes on many critical energy projects and risks slowing down energy technology development'[4]. In response to these new challenges, the Commission has now issued, in May 2010, a new strategic document ("Energy Strategy for Europe 2011-2020") that is under discussion with stakeholders and within the European institutions. Once the details of this new strategy are agreed upon it is intended to shape all the EU's legislative work in the energy sector until 2020. European Council President, Herman van Rompuy, has requested a special high-level meeting to be held early in 2011 dedicated to the EU's energy strategy. Subsequently EU leaders are expected to come to a formal agreement in March 2011.

Philip Lowe[5] (the EU's Director General for Energy) has pointed out the four main areas that the new energy strategy should address:

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(i) Completion and implementation of legislation (in some cases this applies to the second directives, which date back to 2003): 'proper implementation of already adopted legislation, including the 2nd and 3rd internal energy market package, is essential to ensure that the market provides the right price signals for investments'.

(ii) Development of infrastructures to enable gas and electricity to flow between Member States without bottlenecks, link Europe to diversified supply sources in third countries, allow renewable energy production (off-shore and on-shore) to feed into the European supply system and enable 'smart' networks so as to allow actions of generators and consumers to be integrated intelligently. Further, the Commission will examine how to speed up authorisation procedures given that local communities are often resistant to energy infrastructure in their

[2] EU leaders offered to increase the target to 30% if other major emitting countries in the developed world and the more advanced developing nations committed to do their fair share under a UN global climate agreement – this offer is still afloat even though the UNFCCC Copenhagen Conference (Dec. 2009) did not deliver the preconditions

[3] Final Report, April 2010, "A Smart EU Energy Policy" sponsored by the Clingendael International Energy Programme, the Loyola de Palacio Programme of the European University Institute, the Fondazione Eni Enrico Mattei and Wilton Park

[4] Commission "Stock taking document: Towards a new Energy Strategy for Europe 2011-2020", July 2010

[5] Philip Lowe: born Leeds 1947, read PP&E at St. John's College, Oxford (1968), holds M.Sc. from London Business School, entered European Commission in 1973 duly becoming DG for Development, Competition prior to DG for Energy in Feb. 2010

neighbourhood (so far, it has always failed in its efforts to do this). It also wants to increase coordination between EU member states to develop key infrastructure projects of European interest and, with regard to financing, the Commission notes that ‘network investments should in future continue to be financed mainly from tariffs paid by the users’ – an important issue for investors. Nevertheless, it adds that not all infrastructure investments can be delivered by the market alone…..the taxpayers will have to pay their share as well.

(iii) Focus more on 2050; but not meaning the Commission will not take action anymore on the 2020 targets - quite the contrary. According to the Commission, there is still much to be done to achieve these objectives. However, ‘There are no individual targets on Member States’ - hence, it has now entered into a dialogue with Member States on how to determine national targets.

(iv) Establish a coordinated external energy policy building on the bilateral dialogues and closer cooperation already achieved with a number of countries and organisations. The Commission wants its external energy policy to increase its security of supply. Furthermore, the Commission is calling for action with the EU’s traditional suppliers such as Russia, Norway and Algeria in order to promote ‘stable bilateral relations through innovative means including possible mechanisms to leverage the EU’s buying power’. The climate change agenda has also made its way into bilateral energy dialogues.
UNQUOTE

Whilst this is an energy strategy *per se* it does not appear clear that climate change considerations are front and centre within it; its fundamental premise is that European energy supplies and distribution networks for gas and electricity must continue to be expanded and diversified as an enabler of economic growth and the advancement of society. One cannot help but feel that there might be some contradictions here with the “20-20-20” targets. Indeed, this is largely what the promoters of “A Smart EU Energy Policy” and the “Roadmap 2050” (ECF) are saying.

Meanwhile, the somewhat disappointing outcome of the UNFCCC Copenhagen Conference in December 2009 will be followed up in Cancun, Mexico (COP16/CMP6) in the period 29 Nov. – 10 Dec. 2010. Many commentators are of the opinion that a breakthrough in Cancun for an agreement to replace the first commitment period of the Kyoto Protocol (2012) is remote, and whether the EU delegation can make any sort of impact to promote or to validate their “20-20-20” targets is questionable given their poor form on home territory in Denmark last year.

(1.2) THE UK’s RESPONSE TO ENERGY AND CLIMATE CHANGE CHALLENGES

(1.2.1) UP TO YEAR 2000: UK energy policy largely goes back to the arrival of North Sea oil and gas in the 1960s and, in passing, it is worth noting that, despite several discoveries of gas in the Southern Basin, oil companies had lost interest by 1968 because of the low prices offered by the monopoly buyer British Gas and the Labour Government’s ban on gas export. However, the discovery in 1971 of the Frigg Field in the Northern North Sea – the largest and deepest natural gas field at the time – started a new era in the UK’s energy supply. Two huge (32" diameter) subsea gas pipelines were constructed to St. Fergus in Scotland, a distance of 360km. Frigg started operation in 1978 and closed in 2004 and is now undergoing decommissioning but the pipelines are still in use having been connected to several other offshore oil and gas fields in the area.

Frigg’s timing was fortunate, as it happens, since the 1979-1997 Conservative Governments pursued market liberalisation such that state controlled enterprises were dismantled and privatised, for example: BP, the CEGB, British Coal and British Gas. Newly privatised power companies initiated the “dash for gas” since gas was seen as a cleaner and cheaper alternative to coal. This reduced the demand for coal and the miners’ strike of 1984, fought hard against by the Thatcher Government, resulted in the long term demise of both trade unions and the coal industry in the UK. But, the incoming Labour Government (1997) under the guise of energy security – but more likely intending to soften the impact of job losses in the coal industry – immediately issued a temporary moratorium on the construction of new gas-fired power stations (the “Stricter Consents Policy”) which lasted for 3 years until rescinded by the Secretary of State for Trade and Industry in November 2000.

Under the Conservatives another energy policy was pursued; that to encourage nuclear power generation but, expecting a public outcry, they broadened the concept into the 1990 “Non-Fossil Fuel Obligation” (NFFO) to force generators to produce electricity from sources other than coal or oil and gas thereby subsidising nuclear power generation. The NFFO was replaced by the Renewables Obligation (RO) in 2002 – which excluded nuclear generation – and which is still with us (till 2018), administered by Ofgem.

This brief retrospective has been used to demonstrate the vicissitudes of UK energy policy during the 1980s and 1990s thus highlighting the uncertainties constantly faced by investors in the energy industry who not only make large and very long term investment decisions, but who naturally carry the commodity price risk and are subject to whatever fiscal terms governments chose to impose as time goes by.

(1.2.2) FROM YEAR 2000: The first solid recognition of the fossil fuel / carbon linkage to climate change in the UK must be the February 2003 Energy White Paper "Our Energy Future – creating a low carbon economy". On March 13, 2007, a draft Climate Change Bill was published following cross-party pressure over several years. The Bill proposed to put in place a framework to achieve a mandatory 60%[6] cut in the UK's GHG emissions by 2050 (compared to 1990 levels), with an intermediate target of at least 26% by 2020.

The Bill was passed into law in November 2008 as the landmark "Climate Change Act" which made the UK the first country in the world to lay down in law such a significant and long-range carbon reduction target[7]. The Act creates a legally binding framework making it the duty of the Secretary of State to ensure that the net UK carbon account for all six Kyoto greenhouse gases for the year 2050 is at least 80% lower than the 1990 baseline. Then, in April 2009, the government set a requirement for a 34% cut in emissions by 2020 in line with the recommendations of the Committee on Climate Change. However, today, pressure is mounting to apply a 42% reduction target for 2020 – which was to apply if a global deal had been achieved in Copenhagen.

An independent Committee on Climate Change (CCC) was formally launched in December 2008 with Lord Adair Turner as its chair in order to provide advice to the government on the targets and related policies. The current status of the UK's efforts are provided in the 2nd Progress Report to Parliament by the CCC ("Meeting Carbon Budgets – ensuring a low-carbon recovery") of June 2010 in which it was noted – with respect to gas – that (i) a significant potential for gas CCS might exist and that at least one such CCS demonstration plant should be considered, (ii) consideration should be given to extending an Emissions Performance Standard for conventional gas fired power generation, and (iii) CCS should be obligatory for new gas fired power generation plant beyond 2020.

Already, the new UK Coalition Government has indicated its support for the Climate Change Act and provided some signals as to where its emphasis will lie[8]. Chris Huhne has said he believes that the real challenge is to build a different kind of economy and to create a new partnership between business and Government and that this requires a commitment to a consistent policy set for the long term.

He has declared that simply going back to dependence on fossil fuels would be folly, making us vulnerable to oil price spikes and volatility and denying us opportunities for green growth, rich in jobs, and export chances in the low-carbon markets that are expanding around the world. He believes that the UK has enormous potential in renewables and that, thanks to the Renewables Obligation, onshore wind has become cost competitive; the UK is already the world leader in offshore wind and is also supporting wave and tidal stream.

On energy security, given an uncertain world, he states that we need security of supply at home and abroad and that the UK faces a massive challenge; no less than £200 billion of investment will be needed in energy infrastructure over the coming decade. And, to underpin investment decisions, Huhne believes that we need a meaningful carbon price; the current price is simply not doing this.

A quote from the speech: "The case, to me, is clear – we must fix ourselves on a path to a decarbonised society and economy, stimulating growth while meeting the twin challenges of climate change and energy security. The challenge – I look at these challenges in the same terms as businesses and investors – in terms of risk and reward."

So, the conclusion that I draw from the current pronouncement is that the Secretary of State for Energy and Climate Change has opened the door for business to "do the right thing" and will encourage, cajole, enforce or otherwise take steps to achieve the objectives of the Climate Change Act. However, does all this provide adequate comfort for the energy investor, particularly if he is contemplating major investments in new technologies, major plant, or where overall economics are uncertain? Again, is there a contradiction between the ambition for energy security and the drive for expanded use of renewables – most of which are "intermittent" – and how and who will establish a "meaningful carbon price"?

SECTION TWO: ASPECTS OF FOSSIL FUELS AS PRIMARY ENERGY SOURCES / FOCUS ON LNG

(2.1) FUNDAMENTALS OF THE FOSSIL FUELS INDUSTRY

The fossil fuels industry (coal, oil, gas) is a natural resource exploitation industry characterised by large investments in a multiplicity of projects with long time spans coupled with technical, human, geological, price and financial risks and in an environment where politicians invariably involve themselves. The projects themselves are normally large since they are dictated by geological endowment and require economies of scale to be successful and consist of drilling or mining operations, basic physical processing of the raw product and

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[6] In October 2008, on the recommendation of the CCC, this was revised to 80% and became so in the Climate Change Act

[7] Separately, the devolved Scottish Government has its own energy policy (which is at variance with UK policy); the "Climate Change (Scotland) Act" was adopted in August 2009

[8] E.g. refer to the "Economist UK Energy Summit", 24 June 2010, where Chris Huhne spoke

transportation infrastructure to get product to market. The global nature of fossil fuels means that, to a large extent, global pricing prevails and this is dictated by markets' perceptions of supply and demand in the immediate and near term.

Given the scale of the projects and the fact that winning natural resources instantly realises the market value of the commodity concerned, governments often take a great interest in the business since it can be a source of tax revenue (in many cases, special petroleum or hydrocarbon taxation exist) and if the national scale is significant it can offer major employment (e.g. coal mining, offshore construction) which can, in some cases, be supported by subsidies or incentives, e.g. if the inherent production cost is high relative to size of the deposit being exploited when exploitation is in the national interest. However, taking account of the business risks, not least the geological risks, it is clear that not all projects are successful and exploration or appraisal of new fields / areas might result in zero or uneconomic resources being discovered and as a result large write-offs can occur. This aspect often means that finding third party finance for fossil fuel exploitation can be difficult.

The oil and gas industry is characterised by the "upstream" segment comprising the acquisition of rights and the investments necessary to explore, appraise and produce a given field. The scale, capital and risks involved mean that this is usually a game for large international oil companies (IOCs), which may operate onshore in any sort of environment (desert, arctic, jungle) or offshore in rivers, swamp, continental shelf or deep water (e.g. where it might be 1km to reach the seabed) and then they will often work in joint ventures with one capable company designated the operator. In resource rich countries a national oil company (NOC) is often designated to participate in the joint venture as a precondition and may be a full paying partner (under a tax-royalty joint venture) or carried if a production sharing contact (PSC) has been awarded. The nature of the business – with long time lines, multitude of risks, unknown future price outlooks, uncertain regulatory regime, economic challenges and so on – means that financing is almost exclusively equity or corporate borrowings (in the case of an established IOC). A consequence of all of the above is that economic parameters for the upstream industry have to show a substantial return and value added on a fully risked basis in order to be viable.

The upstream oil industry timeline is long: exploration, appraisal and, assuming success, negotiating contracts and partnerships can take 3 to 4 years, construction and installation of production facilities (offshore platforms, onshore gathering stations with separation and pumping equipment and pipelines and ship loading facilities) the drilling of wells can take 5 to 8 years, followed by the operating phase which is from 8 to 20+ years, after which dismantling, restoration and abandonment of facilities and plugging wells has to be carried out.

"Midstream" and "Downstream" segments consist of refining and marketing petroleum products.

(2.2) THE SPECIAL CASE OF NATURAL GAS AND WHY LIQUEFACTION IS RELEVANT

Conventional[9] sources of natural gas occur either as "associated" gas (AG) along with crude oil production or as "non-associated" gas (NAG) in which case some heavier hydrocarbons are usually present (but not crude oil as such) which have to be separated out to make the gas meet the required standards for industrial, commercial and domestic consumption.

Traded natural gas is predominantly (around 90-98%) methane (CH_4) plus a small percentage of ethane (C_2H_6) and lesser amounts of other components, which include water. The heavier hydrocarbons found with NAG include propane (C_3H_8) and butane (C_4H_{10}), together called LPG (Liquefied Petroleum Gas) – colloquially known as bottled gas or camping gas – and the residue of essentially pentane, hexane and traces of higher hydrocarbons – often called condensates or sometimes natural gasoline. In fact, these heavier products are very valuable in their own right or as chemical plant feedstocks and command a market price in excess of that for natural gas itself.

During the upstream processing of the raw products from an oil or gas field, natural gas in the typical composition described above will be released and is then dehydrated to remove water vapour before being compressed for forwarding by pipe to the next ("midstream") process. If the gas is to be sold as a pipeline gas product it has to be "conditioned" to meet the standard specification required meaning that propane and butane (LPGs) and natural gasolines (pentanes+) have to be removed as well as all water leaving virtually only methane with a small of percentage of ethane. The gas will then be compressed to high pressure and sent by long distance pipeline to the customer.

If liquefied natural gas (LNG) is the desired product then the processed natural gas from the field is passed through a refrigeration plant where it is liquefied using a staged / sequential procedure (various patented processes to do this exist) to reach the temperature of -160ºC at which methane condenses to become a liquid at atmospheric pressure. In the liquefaction plant as the temperature is progressively dropped the heavier hydrocarbons will condense out first and in sequence: the heavier ones first at the relatively higher temperatures and so on down to -160ºC. The sequence of temperatures at which the gases condense at atmospheric pressure is:

[9] Refer to Section 3.1for definition

- Pentanes and heavier hydrocarbons: 36ºC. and above (hence these will be liquid droplets in the gas stream)
- Butane: 0ºC.
- Propane: -42ºC.
- Ethane: -89ºC.

Note that the point at which a gas condenses to form a liquid is synonymous with its boiling point (just think of water being boiled to produce steam (a gas) and then the steam condensing on a cool surface to condense back to water (a liquid) again).

The heavier products removed in this way can be sold as refrigerated products directly or, often more conveniently, returned to their gaseous state by re-vaporisation (heating) and then compressed into high pressure cylinders or spheres at ambient temperature for transportation and end use (handling pressurised containers is easier than refrigerated ones).

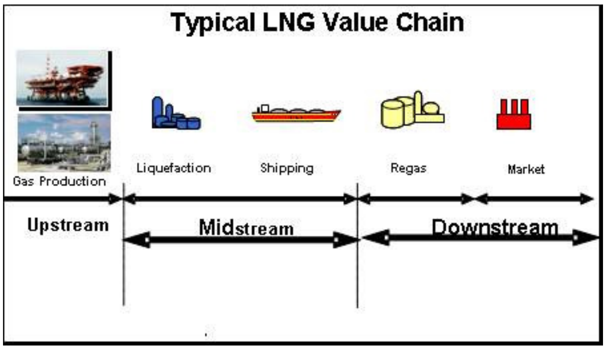
In all the above it is worth noting that special materials are required to handle the cryogenic[10] temperatures such as a high nickel steel alloy under the trade name of "Invar"[11] for piping and process equipment or aluminium / other alloys for tank linings.

Liquefying natural gas means that it can be transported by ship around the globe versus the use of fixed pipelines. The final stage of the LNG chain is where a receiving terminal for the LNG ship allows for transfer via special handling equipment into onland refrigerated storage. In order to utilise the LNG as gas for sale by pipeline it requires regasifying which is a relatively simple process of heating the liquid with perhaps hot water or other medium in a large "kettle" to take it to ambient temperature once again. This is the essential function of the LNG receiving / regasification terminal in the end users country. Note that the LNG is not under any significant pressure during these processes but that the resultant gas must be compressed to transmit it by pipeline.

The driving force behind any project to liquefy natural gas and to ship it to foreign destinations is the fact that the gas resource in a given location is so far away from a market that installing a pipeline to transport it is not realistic or is uneconomic. This is the problem of so-called "stranded gas" – an example being natural gas discovered in Qatar[12] which has now several liquefaction projects to allow the gas to be shipped around the world. Similarly, Nigeria has been producing and exporting LNG since 1999, whereas gas produced from large fields such a Groeningen in the Netherlands has simply needed to be integrated into a pipeline network since the market is on the doorstep. North Sea gas, back in the 1960's in the Southern Basin, was connected to shore by pipelines as have been, since then, various gas fields in the remoter Northern waters. However, for liquefaction of natural gas to be viable the size of the resources needs to be big enough to justify the tremendous investments necessary – in all sections of the LNG value chain.

(2.3) LNG PRODUCTION, TRANSPORT, TRADE, MARKETING

As alluded to, the LNG business is considered a value chain, with most stages having interests held to a greater or lesser extent by the sponsors of the original upstream business (oil/gas exploration and production). This means (i) value can be captured for sponsors along the various stages of the chain, accepting that some stages such as shipping are a pure cost component, and (ii) market, price and other risks are distributed along the chain such that absolute exposure to one element such as upstream field gas production or end product natural gas sales price are narrowed.



Now, we are at the stage of enlightenment with respect to natural gas: when liquefied at -160ºC and atmospheric pressure LNG occupies a volume 1/600th of the volume it does as natural gas. This incredible fact is the driver

[10] Cryogenic: "very low temperature" – usually taken to mean below -150ºC.
[11] Registered trademark of ArcelorMittal S.A.
[12] Qatar's giant North Field (largest NAG field in the world), was discovered in 1971 but only developed in 1991 (for local use). LNG production started in 1997 when the first cargo was exported to Spain. Since 2006 Qatar has been the largest LNG exporter in the world.

for the LNG business and allows for storing and shipping the product at atmospheric conditions, at very low temperature, around the world. The need to keep LNG at such a temperature requires sophisticated insulation which technological advances have perfected such that in LNG carriers travelling international waters for perhaps 3+ weeks continuously experience only very small losses of product through boil-off or sloshing in the tanks.

Another point is that it is much easier to transport and handle a liquid (even a cryogenic one) than a gas; use of ships means that LNG can travel the globe and as such frees the limits that are imposed by use of fixed gas pipelines. LNG has made gas a fungible commodity which is increasing competing with other gas on a global scale.

(2.4) SUMMARY OF LNG'S UNIQUE FEATURES

- LNG technology is well proven and relatively simple
- Globally transportable liquid requiring purpose built vessels
- At present few ships available for spot charter but this is changing with LNG market downturn
- Vessels can be diverted to different customers if need be, compared with potential for pipeline supplies to be subject to interruption if transit countries are involved
- Ports are needed, with special cryogenic loading, unloading and storage facilities
- Extremely high initial capital cost per project – usually $10+ billion
- Feed gas to a liquefaction plant if associated with a producing oil field can offer the potential for significant incremental economics if the gas handling system is minor in relation to the crude oil facilities investments
- Long term contract needed to support initial capital investment and for financing / non-recourse financing preferred / usually required – or some form of project financing
- Project economics often enhanced by value of LPG's and condensates / natural gasoline
- Product is globally fungible and competitive with pipeline delivered gas
- LNG in storage provides a peak-shaving opportunity in the receiving country
- Liquefaction plants need dedicated gas supply contracts from fields, areas or defined reserves to support investment and the LNG sales contracts
- Whilst contracts are long term, increasingly the sales contracts have flexibility built in – e.g. destination flexibility and for upside value sharing if uplift can be achieved, also today sellers will be open to negotiation to compete with pipeline gas prices if below contracted ones
- LNG has an excellent safety record. It will not explode or burn. It is not hazardous to health. In case of spillage it will float on water and slowly evaporate.

(2.5) HISTORY AND CURRENT STATUS OF LNG IN THE ATLANTIC BASIN

(2.5.1) GENERAL LNG HISTORY:

Ocean shipments of LNG started when an experimental transatlantic cargo was successfully shipped from Louisiana to Canvey Island for the North Thames Gas Board in 1959. LNG trade itself actually commenced in 1964 with deliveries from Algeria to the British Gas Council and Gaz de France. However, the development of trade has been spasmodic and has featured different drivers in the Atlantic and the Pacific basins where trade, until recently (i.e. until Qatar came on the scene in 1997), has been concentrated.

Interestingly, 1969 saw the start-up of the Alaskan LNG Plant at the Kenai Peninsula which provided LNG to Japan. This plant is one of the oldest LNG plants in the world, celebrating its 40th year of continuous operation in 2009 and has now had its licence extended to 2011. This demonstrates the commercial opportunities able to be captured by LNG i.e. remote (or "stranded") gas can be commercially liquefied and shipped to customers when either pipeline transportation is not feasible and when no local market exists.

In the 1970's it was perceived that the USA (lower 48) was to experience a domestic gas shortage and so four LNG receiving terminals were built on the Atlantic coast, in addition to the existing one in Louisiana. For various reasons (policy changes, prices, disputes) the trade did not amount to much and activity declined from 1979 lapsing quickly thereafter until reactivation in early 2000 when additional imported gas for power generation was needed.

Until recently the USA has been an important customer for LNG (22 BCM imports in 2007) with 8 receiving terminals in operation. Import volumes declined to 12.8 BCM in 2009 and represented just 2% of the total US gas consumption.

(2.5.2) CURRENT ATLANTIC BASIN STATUS: The present excitement over the availability of major shale gas resources in the USA along with the global recession has created a second hiatus for LNG trade resulting in the current LNG surplus in the Atlantic Basin. Indeed, there is even talk of the USA exporting LNG given its current and projected surplus of gas; this clearly is putting downwards pressure on natural gas prices, on both sides of the Atlantic – compounded not only by excess LNG export capacity today but new liquefaction projects (along with their newbuild LNG ships) that are under construction at this time. Furthermore, on the demand side, the global economic downturn has impacted traded gas volumes, hence depressing wholesale prices.

At the global level, LNG trade in 2009 amounted to 243.0 BCM versus 226.5 BCM in both 2008 and 2007, with 209.4 BCM in 2006[13].

(2.5.3) UK LNG HISTORY: The UK started importing LNG from Algeria in 1964 through the 1970s into Canvey Island but with North Sea gas supplies stepping up rapidly from the late 1970s (Frigg field, etc.) the UK LNG industry closed down in 1990 and the Canvey Island receiving terminal was dismantled. Now, like in the USA, things have gone full circle – in July 2005 a new LNG receiving terminal (initial gas send out capacity 4.4 BCM per year) started operation on the Isle of Grain (for National Grid), followed by South Hook LNG – the largest terminal in Europe – (owned by Qatar Petroleum, ExxonMobil and Total) in late 2009 and early 2010 and Dragon LNG (owned by BG, Petronas and 4Gas) in September 2009, both in Milford Haven, Pembrokeshire. Also, the Teesside GasPort (Excelerate) started operation in early 2007. Furthermore, the defunct Canvey Island LNG terminal that has been used by CalorGas for LPG imports now is reapplying for permission to convert to an LNG receiving facility. All this activity in the UK was triggered by the winter of 2004/2005 when the UK became a net importer of natural gas as a result of the progressive decline in North Sea production. UK natural gas production had peaked in 2000 and has declined from 108.4 to 59.6 BCM per year in 2009.

Whilst it is accepted that the UK already has several pipelines bringing North Sea gas from the UK and the Norwegian sectors (into St. Fergus, Teesside, Easington, Theddlethorpe and Bacton) and two interconnectors with continental Europe (Bacton-Zeebrugge, Belgium ("IUK") and Bacton-Balgzand, the Netherlands ("BBL") - since December 2006, with a capacity of 16 BCM per year) which provide also for back-up volumes from Russia, the flurry of UK LNG activity shows the liberalised market at work with LNG exporters seeing the opening UK opportunity and being willing to compete with pipeline supplies. Also, this new LNG into the UK favourably adds to security of supply and, incidentally, potentially provides a boost to national gas storage volumes – for considerations of peak-shaving – since LNG is stored as a liquid until it is regasified and then fed into the grid.

In 2008 the UK imported under 1 BCM through the Isle of Grain, mostly during the winter months of late 2008. Grain saw the completion of its Phase 2 in late December 2008 taking total gas send out capacity to 13.3 BCM per year. A Phase 3 is underway for winter 2010/11 taking send out capacity to 19.5 BCM per year and a Phase 4 is under consideration. The UK's import capacity increased further in September / October 2009 with the commissioning of South Hook Phase 1 (10.5 BCM per year) and Dragon (6 BCM per year). South Hook Phase 2 was completed in April 2010 doubling capacity to 21 BCM per year of gas send out and Dragon is planning an expansion to 12 BCM per year.

As mentioned, LNG importation facilities also exist, since February 2007, through ship to shore transfers at Teesside GasPort where a dockside LNG regasification facility onboard a ship is located owned by Excelerate Energy of Houston, USA. This is the first project in the world where LNG will be regasified onboard ship in a port and pumped directly into a pipeline for entry into the national transmission system. Whilst not expected to be a base load facility, the capacity is potentially 4.2 BCM per year. So far two ships have delivered LNG through this facility; the last ship was in April / May 2009.

In total in 2009 UK LNG imports amounted to 10.2 BCM, in addition to pipeline gas imports from abroad of 30.9 BCM, out of the total UK gas market of 86.5 BCM. During October 2009, LNG made up almost 18% of total UK supplies and on a daily basis the maximum LNG flow to date has been 72 MCM on the 11th November which was equivalent to over 22% of total UK supply for that particular day.

(2.5.4) CONTINENTAL EUROPE LNG: In continental Europe France, Spain, Italy, Portugal, Belgium, Netherlands, Turkey and Greece, have LNG receiving facilities and several other countries have plans for them too.

France's LNG industry dates back, like the UK's, to the 1960s and today there are 3 Gaz de France terminals in operation, two near Marseilles and one on the Atlantic coast at the Loire estuary with a total capacity of 19.4 BCM send out of natural gas. They receive product mainly from Algeria and Nigeria but other sources are coming in such as Egypt and Norway (Snøhvit). France's LNG supply in 2009 is about 25% of the gas market (of which Algeria supplied 17%) with pipeline gas providing the rest – from Norway (35%), Russia (21%) and the Netherlands (14%).

Whilst France has significant nuclear power generation, it is interesting to note that gas used for power generation more than doubled between 2000 and 2009, from 3.5 BCM to 7.7 BCM. Around 3.8GW of gas fired power plants are expected to come onstream between 2010 and 2012 – by EDF – leading to an additional 3 to 4

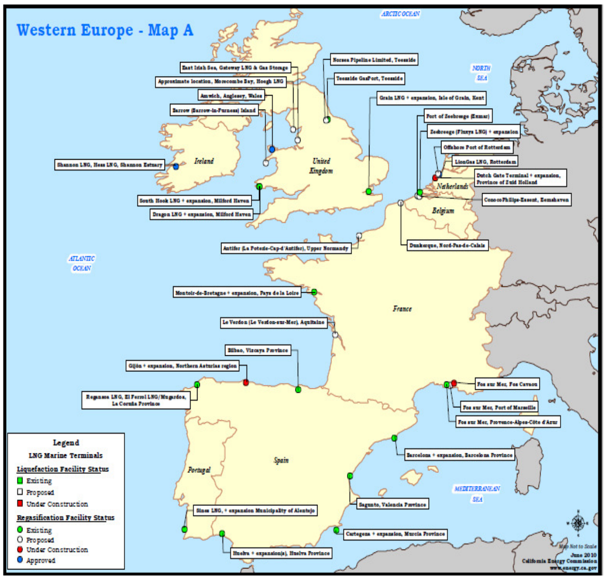
[13] Source: Bloomberg

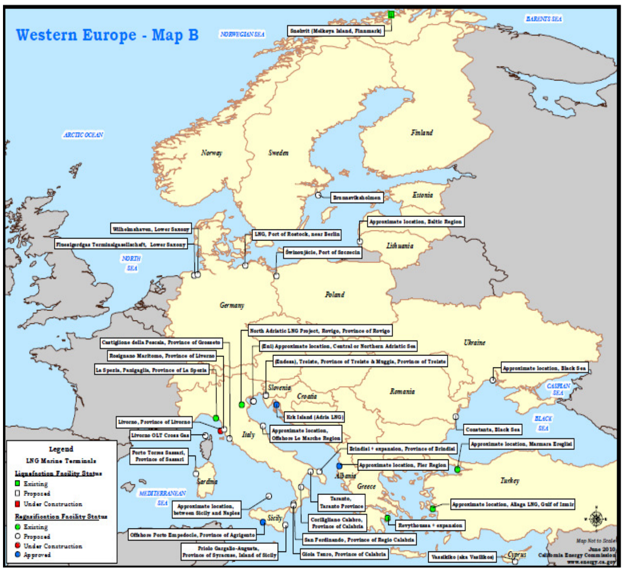
BCM of gas consumption. Other generators, Poweo and GDF SUEZ, each started a 400MW combined-cycle gas turbine in the 3rd and 4th quarter 2009, respectively.

Spain is a gas poor country but has a notably diverse supply; gas pipelines from France and Algeria (MEG line via Morocco – commissioned 1996 – and the new Medgaz line – under commissioning August 2010) and 6 LNG terminals including the Mediterranean and Atlantic coastlines with another 1 under construction. Imports have come from Algeria, Nigeria, Trinidad, Qatar, Oman, UAE, Libya, Australia and Brunei.

Today Spain has about 74% LNG supplying its national gas demand with power generation taking about 35% of the gas (ahead of coal at 15% in the power sector).

Italy has 2 terminals with 10.4 BCM current total capacity since 1971. Portugal has a single terminal with 5.5 BCM capacity from 2004. Greece has a terminal with 5.3 BCM since 2000 and Turkey has 2 terminals of 5.0 BCM, since 1994 and another of 6.0 BCM from 2006. These and several other countries have plans for addtional terminals.





Source: California Energy Commission, July 2010

(2.6) STATUS OF GAS MARKET IN EUROPE

By way of background, the European (EU27) natural gas industry represents (2009):

- 24% of primary energy consumption
- 114,000,000 customers
- 255,000 employees
- 2,000,000 km of pipelines.

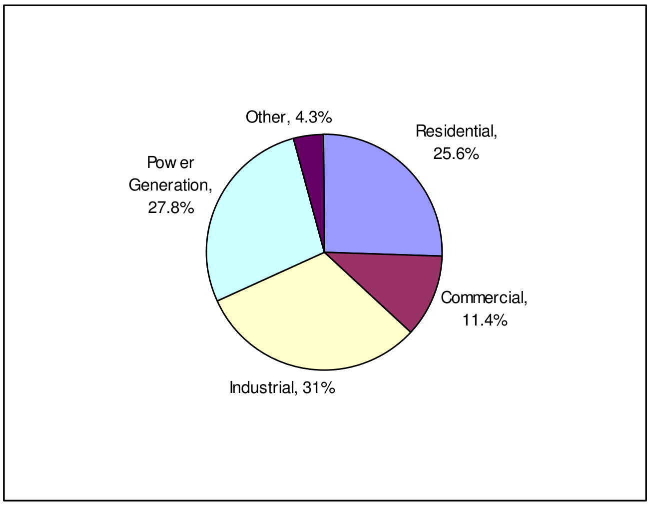
Gas consumption statistics[14] (note: 2008) are shown below for some of the larger gas consuming countries in the EU along with the total EU27. Values are in PJ (1 PetaJoule = approx. 1 Trillion BTUs)

Country	Residential	Commercial	Industrial	Power Generation	Other	Totals
Belgium	166.1	79.8	243.5	196.4	0.0	685.8
France	646.0	288.0	722.0	194.0	11.0	1861.0
Germany	970.0	410.0	1310.0	450.0	170.0	3310.0
Italy	826.8	312.4	699.5	1306.8	88.5	3234.0
Netherlands	323.6	404.5	580.3	306.0	0.0	1614.4
Spain	162.0	50.6	728.5	675.3	0.0	1616.4
United Kingdom	1320.0	369.0	500.0	1436.0	304.0	3929.0
EU27	5149.8	2288.4	6231.2	5598.6	855.5	20123.4

14 Eurogas Statistical Data for 2008

Expressed in different units, EU27 gas consumption in 2008 was 536 BCM or 479 MTOE while it declined by 6.4% in total in 2009 due to the economic crisis. The UK[15] itself consumed 93.8 BCM or 84.4 MTOE in 2008 declining to 86.5 BCM or 77.9 MTOE in 2009 (7.5% decline).

An analysis at the EU27 level gives the following in percentage terms:



It is apparent from this chart that there is a real challenge if considerations of reducing dependency on fossil fuels, because of climate change concerns, would really require the phase out of natural gas. What are the likely substitutes to be in each of the sectors shown?

Electricity (produced from other than gas firing) clearly could provide some substitution in the residential sector for home heating, hot water and cooking. With regards to the commercial and industrial sectors it is less sure that electricity can fit the bill depending to what extent gas is used in either industrial processes or as a raw material for conversion. In any case, it is costly to convert from one fuel use to another and it may not be feasible, or an economic proposition in certain industrial processes, to abandon the use of gas given, for example, its controllability. Then again, would European industry – the largest user of natural gas – be disadvantaged competitively if it had to move away from gas use?

Regarding gas for power generation; on one hand this could certainly grow as existing coal fired power plants are retired to be replaced by gas firing, or as generators choose preferentially to build new gas fired plant. But coal fired generation may not be significantly displaced by gas fired generation until carbon prices reach relatively high levels.

The displacement of gas in the power generation sector would have to come from renewables or nuclear, yet it is hard to see how either could address the capacity (from renewables) or deliver in a reasonable time frame (from nuclear) such that gas is quickly displaced. Then again, gas fired generation may be necessary as a capacity back-up for intermittent renewable resources; sources like wind and solar are intermittent - when the wind doesn't blow and the sun doesn't shine, something has to pick up the slack, and that something is likely to be gas fired electric generation which has the flexibility to respond quickly.

When it comes to gas vs. coal for power generation, the high efficiency of CCGTs (Combined Cycle Gas Turbines) offers major environmental benefits. Replacing a coal plant which is 30-40% efficient with a CCGT which is 50-60% efficient reduces primary energy consumption drastically, and can more than halve the plant's CO_2 emissions. Among the advantages of natural gas fired power stations are their ease and low cost of location, speed of construction, and flexibility in use. Of all fossil fuels, natural gas has the lowest CO_2 emissions per unit of energy[16]. It has no pollutant-forming components, it is free of sulphur dioxide (SO_2) and particulates in combustion, and emits very low amounts of nitrogen oxide (NO_X) when burned.

Meanwhile there is significant gas fired power generation capacity currently under construction in Europe – possibly around 40 GW to be commissioned between 2010 and 2013.

Finally, assuming the successful deployment of CCS on an industrial scale, this can be applied to gas fired plant, not just to coal fired, thereby substantially reducing CO_2 emissions. Since, CO_2 emissions from gas firing are, in any case, less than half those of coal emissions the capital cost of CCS applied to gas firing will be lower than that applicable to coal plant. It is noteworthy that Lord Adair Turner, chair of the UK Climate Change

[15] Source: BP Statistical Review of World Energy 2010
[16] Emissions from coal-fired power stations are estimated to be 830g of CO2 per kWh hour of power generated - compared with 380g for gas.

Committee, mentions in his June 2010 report[17] "new analysis has suggested a significant potential role for gas CCS".

SECTION THREE: BRIEFING ON UNCONVENTIONAL GAS / SHALE GAS

(3.1) CONVENTIONAL VS. UNCONVENTIONAL GAS

Natural gas whether it is associated (AG) with crude oil production or is non-associated (NAG) occurs in the conventional sense of being trapped in a geological formation something like an upturned basin (an anticline) or against the wall of an impervious rock in a geological fault. The oil or gas is found in rocks that have sufficient porosity and permeability to allow the fluids to flow – such as sandstone – which are under the impervious or cap rock which forms a seal. It is apparent therefore that conventional hydrocarbons must have a cap rock to contain them otherwise they would have dispersed a long time ago. The accumulations are in medium to highly porous reservoir rock with sufficient permeability to allow gas to flow to producing well. The pressure regime is such that it tends to move the gas towards the well bore by natural flow.

In the case of unconventional gas these are deposits of natural gas found in relatively impermeable rock formations – tight sands, shale and coal beds. To get the resources out of the ground, artificial pathways (fractures) have to be created and wells are produced by drilling horizontally into the rock and using modern fracturing techniques.

There are essentially four variants of unconventional gas which differ with respect to the trapping mechanism:

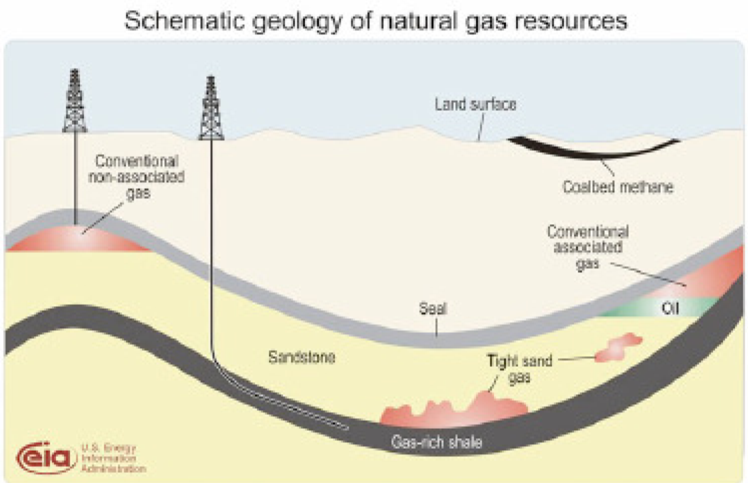
Coalbed Methane (CBM) – which is an abundant and well-known energy source and is now becoming easier to produce because of improved finding and transporting mechanisms. CBM was known to miners in the old days as "fire damp" and has been produced commercially since the 1980s

Shale Gas – organically rich gas shale reservoirs have been largely ignored by oil and gas companies, mainly because of the challenges and costs in their production, in favour of easier plays and faster returns

Tight Gas – True "tight gas" reservoirs require advanced knowledge and special techniques to enable reduction of the migration-distances from formation to well

Gas Hydrates – seismic surveys suggest that gas hydrate accumulations are abundant in offshore areas around the world. These deposits consist basically of gas disolved in frozen water and they are also prevalent under permafrost in some arctic regions. Production of gas hydrates is the "next frontier".

The consequences of the above are that companies need to understand the geology better, including how the gas was formed in the first place, and to determine the optimum number of extraction points (which is significantly higher and hence costlier than for conventional reservoirs). However, better reservoir knowledge and new technologies are making the production of unconventional gas economically viable and more efficient. This efficiency is bringing unconventional gas within reach of companies around the world.

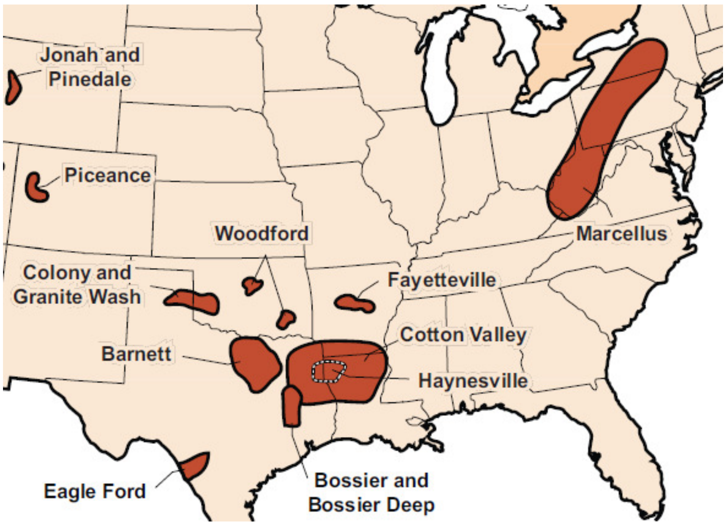


(3.2) UNITED STATES HISTORY

[17] 2nd Progress Report to Parliament by the CCC ("Meeting Carbon Budgets – ensuring a low-carbon recovery")

In the USA the shale gas "revolution" or "shale gale" has hit the news within the last few years and represents a potentially new and large resource of natural gas. Given the decline of conventional gas reservoirs the shale gas opportunity, assuming resources can be converted into significant volumes of proved developed reserves, can impact the need for importation of LNG which has been expanding at a high rate hitherto.

Knowledgeable industry commentators note that shale gas, and other forms of unconventional gas, have exhibited much more of an evolution than a revolution; in the USA the first discovery of shale gas goes back to 1821 (in the Appalachian Basin's Marcellus Shale) but it is in the period 1979 to 2007 that serious effort had been put into understanding the resource and applying technology to this difficult to access hydrocarbon. The recent explosion of interest really started in 2007 when the deep Heynesville Shale (North Louisiana – East Texas), the giant Marcellus Shale (New York State – Pennsylvania – West Virginia) and the Fayetteville Shale (Arkansas) hit the news – all stemming from intense work in the Barnett Shale of Northern Texas (Fort Worth area) conducted in 2002-03 by Devon Energy Corp. It was only in the 2nd half of 2009 that unconventional gas became a recognised part of the US energy scene; today about 20% of US gas production is from shale (in 2006: 1%).



Source: Geology.com

In Canada's West Coast (north eastern British Columbia) and in Mexico, prospectivity for unconventional gas exists.

Producing shale gas requires extension of existing technologies: horizontal drilling and hydraulic fracturing. Whilst each technology has been in use for decades it is the combination that has unlocked unconventional gas resources.

• Hydraulic fracturing (commonly called "fraccing") involves injecting a high pressure mix of water, sand, and chemicals into the reservoir to generate new fractures in the rock, or to enlarge existing ones. The sand that the fraccing fluid contains is called the "proppant" and its job is to hold the fractures open after the procedure is completed. The particle shape, size and composition of the "sand" is an art which determines the success of unlocking the gas to flow in the rock. Fraccing and propping creates pathways for the gas to move towards the wellbore and then flow up to the surface. In some circumstances, very large volumes of acid are injected into the rock, e.g. if it is a tight chalk, in order to dissolve the rock around the well bore; this is "acid fraccing".

• Horizontal drilling too has also been essential in economically accessing shale gas. This "directional" drilling involves a routine vertical well drilled to the required depth and then turning it to drill horizontally to access a larger portion of the reservoir. Steering the drill bit at thousands of feet underground is now commonplace, however, knowing in which direction to drill requires the geological knowledge that defines success. Originally this was used in the 1980s for oil production in the Austin Chalk (Texas), it has now spread throughout the industry. It is clear that a horizontal well will mean fewer vertical wells have to be drilled in a field but of course the cost (time) of drilling the horizontal well, the cost of complicated completions that can be manipulated from surface, and the heavy duty drilling rigs all mean a significantly higher cost for a horizontal well and fraccing compared with regular wells.

Nevertheless, the evolution in shale gas production has resulted in the cost of production falling, but a broad range of costs have been reported and there is still some uncertainty as to the long run economics given the generally pessimistic forecasts for Henry Hub.

Turning to the environmental side there are two concerns regarding water: to what extent will the chemicals and water used for fraccing the well seep into drinking water, and is the volume of water produced along with the gas handled appropriately? A comprehensive regulatory framework for water management is already in place in the USA with the objective of protecting drinking water supplies. In fact, exploitation of tight gas reservoirs – and this has been known since the start of coal mining and the incidence of CBM – is associated with production of a lot of water, the appropriate treatment and handling of which must be addressed at the outset, today.

So, the speculation will continue as to what extent the USA's expansion of its indigenous unconventional natural gas supplies will reduce its demand for LNG imports. Perhaps LNG importation will become a matter of choice rather than one of necessity; and again, there are sunk costs in many relatively new LNG receiving and regasification terminals with pipeline infrastructure to consider – are they likely to be just quickly written off?

Contrarily, plans to *export* LNG from the US lower-48 reached a milestone in March 2010 when the reloading of a cargo of LNG took place at the Sabine Pass receiving terminal in Louisiana which was then delivered to the Spanish market. Volumes were low and I suspect that the deal may have been borderline commercially given the prevailing transatlantic price arbitrage. The project led by Cheniere Energy Partners will have a liquefaction capacity of 4 trains of 7.2 BCM per year (each train, max.) with 2 trains constructed initially by 2015. It would be the country's second liquefaction terminal after Alaska's Kenai project, but the first to connect to the US grid.

(3.3) EUROPEAN POTENTIAL

Following the shale gas excitement in the USA, there has been sizeable industry interest in the possibilities for shale gas exploitation in Europe; however, early estimates suggest that the European shale gas potential is less significant and therefore unlikely to reverse the increasing need for gas imports whether by pipeline or from LNG. Potential for unconventional gas is about 7 times higher in North America than in Europe[18]. Of course, discoveries and development of significant volumes of shale gas could quickly change the fundamentals of the European market; some companies have set big hopes on indigenous shale gas in Europe.

In weighing and balancing the outlook, there are some distinctly European issues to consider. Firstly, population density in Europe is much greater than in the States and it will be a challenge to develop a new large-scale onshore industry given that hydrocarbon basin histories here are somewhat different and more complicated. Land tenure and the ownership of resources are also very different in Europe and there is a lack of the kind of onshore infrastructure that exists in e.g. Texas. Land drilling rigs in the USA number nearly 1,000 but in Europe there are estimated to be about 100. Obtaining water for the initial fracturing process and handling the large volumes of produced water will be an obstacle too and European well costs – drilling & stimulation – can be up to four times US levels. Fiscal regimes for unconventional gas are not yet in place. In short, the whole value proposition appears precarious; there is no developed production of unconventional gas in Europe at this time; transforming geological potential into profit opportunity is the key challenge.

It is felt, at this point in time, that shale gas will be an addition to the European supply mix but probably its main impact is still some time off; in all probability not really gaining much traction until after 2020. Hence, it will not be a substitute for imports in the medium term. Yet, it could be that shale gas partially makes up for declining North Sea production, but it is unlikely to raise European production above today's levels. Consequently, Europe's long term import needs for natural gas from Russia and elsewhere will grow – subject, of course, to climate change considerations impacting fossil fuel use in general.

According to the IEA[19], an acute global glut of natural gas is anticipated over the next few years as new supply comes on from unconventional sources leading to a restructuring of gas pricing towards spot related gas-on-gas competition. This is good news for gas buyers and will, if true, affect gas users' economics when/if substantially higher carbon prices materialise.

Regarding the prospects for unconventional gas in Europe, current exploration activity is in hand near Vienna, in Germany, Southern France, Hungary, Ukraine, Poland (expect results later in 2010 - ConocoPhillips). In Poland ConocoPhillips is poised to launch Poland's first shale gas drilling programme about now near Gdansk on the Baltic coast.

Two other American oil groups — Exxon-Mobil and Marathon — and Talisman Energy (Canada) with San Leon Energy of the UK are set to follow. Aurelian Oil and Gas – another UK company are exploring in Poland.

Possible plays in the UK, based on known geology, include Surrey, Kent, Hampshire, Cheshire and Nottinghamshire.

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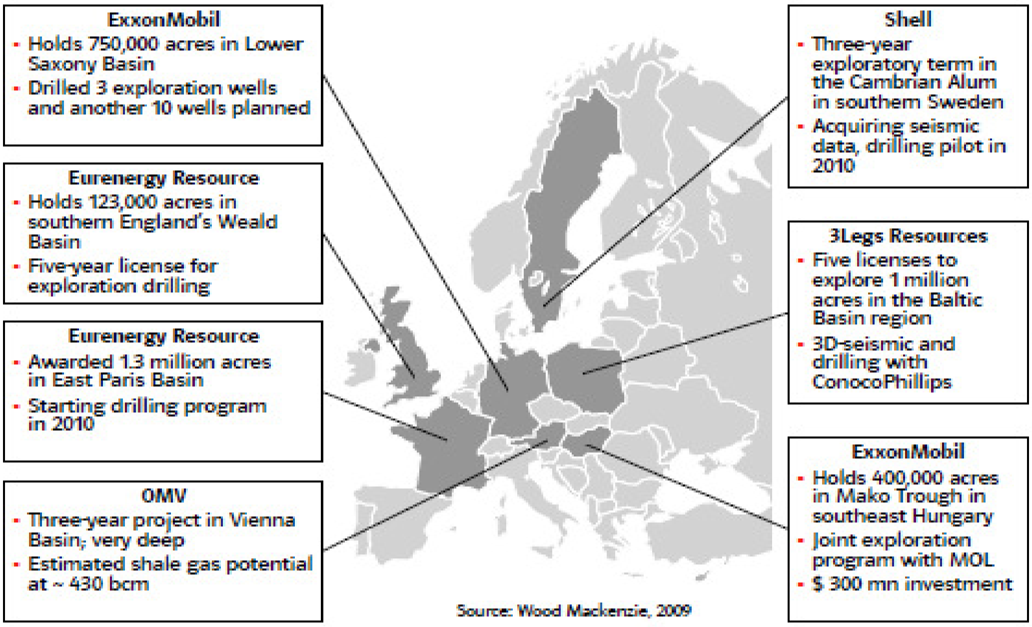
[18] E.ON presentation "Prospects for unconventional gas in Europe", Andreas Korn, 5 February 2010

[19] EIA World Energy Outlook (Nov 2009)



SECTION FOUR: OPINIONS AND DISCUSSION

The application of natural gas to power generation has received a lot of comments from various sources but it would appear that LNG has sparked much less interest, perhaps because it is an intermediate product and perhaps because there are a limited number of players in the field who go about their normal commercial business in a rather mundane manner. LNG activity does not – as yet - have the headline grabbing potential of crude oil or of Russian gas supplies, for example.

Earlier this year (18th March, 2010 at Shell Centre, London), Dr. Fatih Birol of the IEA spoke on the "World Energy Outlook post Copenhagen" and noted the "silent revolution" of US shale gas and the consequence that LNG liquefaction projects planned may not now be needed; a gas glut is coming putting downwards pressure on gas prices and so making gas more competitive. The glut will stay until 2014/15 or even longer and will only disappear with strong economic recovery. Meanwhile, natural gas can be a "bridge fuel" towards meeting the 450ppm CO_2 scenario (≡ 2ºC. rise). This may imply that new investment in LNG liquefaction and regasification will cease until further notice; the returns on investment will just not be there with gas prices as low as indicated.

Earlier in 2010, the UK's Department of Energy and Climate Change in reviewing natural gas imports and exports in 2009 noted in "DUKES" (Digest of UK Energy Statistics 2010): "LNG imports are seen as increasingly important in meeting the UK's gas demand." This certainly appears to be a pointer towards government favour for expansion of capacity at the existing receiving terminals as well as for new ones.

In a January 2008 Communication from the European Commission "20-20 by 2020, Europe's Climate Change Opportunity" referring to CCS it was stated, "Of particular importance is carbon capture and storage (CCS). Fossil fuels will remain the primary source of energy worldwide for decades to come. Stocks of coal will be needed to provide energy in Europe, and to feed the huge rise in energy demand already under way in many developing countries. But the target of halving 1990 global GHG emissions by 2050 will never be met unless the energy potential of coal can be exploited without ballooning emissions. That is why the European Council backed early action to make CCS the technology of choice for new power plants, including the setting up of up to 12 demonstration plants by 2015." Now this might have been an intention declared before the full force of the economic crisis was appreciated, but it takes the stand that fossil fuels will continue in use for the foreseeable future and that CCS will therefore have to be applied in order to meet emissions targets. Now, 2½ years on, the great expectations for CCS appear to have been dampened somewhat and one wonders if generators will take the risk that CCS will come along in a timely manner and be economically feasible as they make today's investment decisions?

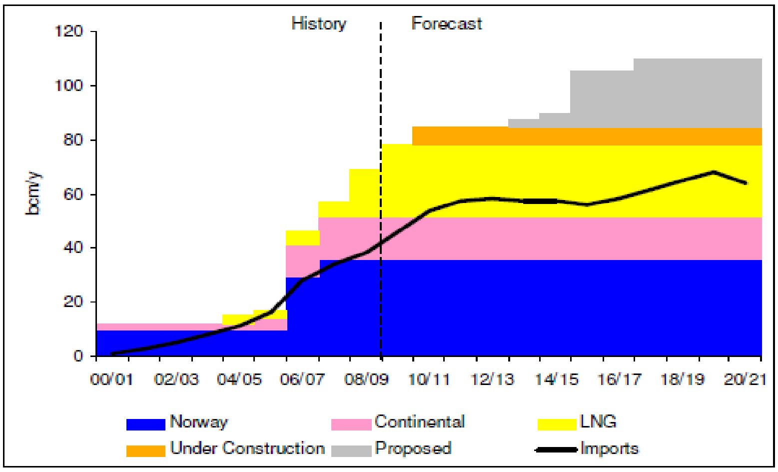
"Gas-fired combined cycle plants remain the most economic choice until CO_2 prices reach relatively high levels. At CO_2 prices of \$80-\$100/ton[20], coal with CCS and nuclear plants start to become a more attractive choice, but CO_2 prices are not expected to reach this level until after 2030. This suggests a window of time over the next 20 years or so in which gas-fired power plants ought to be the natural choice for merchant generation, even with CO_2 pricing." (The Brattle Group, "Prospects for Natural Gas Under Climate Policy Legislation", March 2010).

[20] Equivalent approx: €63 - €78/tonne

Whilst this opinion was produced with the US audience in mind, this paragraph encapsulates the heart of the issue for investors in new generation capacity: if they are not forced (by existing and foreseen carbon prices) down one investment avenue, they will elect that which is most economic at the time of FID[21].

In National Grid's "TBE[22] 2010: Development of Energy Scenarios" (July 2010) some strong opinions are expressed on the outlook for UK gas imports: "In aggregate, the existing and development plans for import capacity is around 170 BCM per year and even higher if all proposals for LNG are included. This far exceeds the UK's projected import requirements at the end of our 10 year planning cycle of about 65 BCM…….. Globally, LNG regasification capacity exceeds production or liquefaction capacity by a ratio well in excess of 2 to 1, i.e. a de-rated level below 50%. Figure 6 shows our view of import requirements against a back drop of de-rated capacity for existing import facilities …….Our current view favours more LNG imports rather than from Continent due to numerous factors ………"

Figure 6 – Import Requirement vs De-rated Import Capacity



I really would have liked to have seen the black line in Figure 6 projected for another 10 or so years – difficult as that might be. Yet, the trend here is clear – as foreseen by National Grid – the 2009 UK gas importation of 41.1 BCM (against total gas consumption of 86.5 BCM) looks set to grow by over 50% to 2020. It may be that the downturn in the black line indicates a structural reduction in the demand for gas or that new sources of indigenous (unconventional?) gas are coming onstream.

In standing back and looking at the EU 20-20-20 targets it is apparent that policy favours zero emission solutions, and that CCS is a fully acceptable component of this. I see little mention of CCS applied to gas fired power generation yet this is an obvious application (assuming that CCS comes forwards as anticipated). Why apply CCS only to coal fired plant emissions when it can be less costly to apply it to gas fired power generation which is more energy efficient anyway?

The goal at 2050 appears to be one of minimal fossil fuel use. Consequently, the EU is supporting expensive electricity solutions when power could be generated more cheaply and more predictably by gas. Security of gas supply long term need not be a worry; diversification of supply can come from the North Sea, existing and planned Russian pipelines, a Fourth Corridor pipeline, expanded LNG terminals, or European unconventional / shale gas resources. Today, given the austerity packages being rolled out across Europe, there might be a case for looking more closely at the appropriate cost-effective and balanced power generation portfolio.

SECTION FIVE: CONCLUSIONS

Natural gas has been with us for over 40 years and has been used in power generation for 25 years.

Natural gas is a fossil fuel and produces CO_2 when combusted, thereby – if not captured – contributes to global warming.

Today, many see natural gas as a convenient bridge to a transformed, low emission, electricity sector that will eventually rely less on conventional coal fired generating plants and more on nuclear plants, coal plants with CCS and renewable energy sources. Yet the ultimate substitutes for gas in the residential, industrial and commercial sectors are not entirely clear and the impact on European business competitiveness due to abandoning gas use is uncertain.

[21] Final Investment Decision, or project sanction
[22] TBE = Transporting Britain's Energy

LNG is established and growing in Europe and is competing with Russian pipeline gas. Commercial business has responded to government policies of liberalisation, diversification, desire for enhanced security of supply and has seized the opportunity to compete, despite ever changing government policies.

The fact is, material interests prevail in a democratic, capitalist society and sunk capital is utilised and incrementally expanded until it is forbidden to do so by law or it becomes uneconomic to operate.

A Force Field Diagram can be useful to analyse LNG's attributes:

POSITIVE FORCES ➔	**🡐 NEGATIVE FORCES**
LNG provides diversification of gas supplies to the EU ============➔	Gas is a fossil fuel – with all its negative connotations 🡐============
LNG technology and terms of trade well established ============➔	Gas prices can be volatile (relative to coal) hence energy prices 🡐============
Economically efficient in power generation ============➔	Indigenous shale gas might come to market 🡐============
Natural gas is the "cleanest" of the fossil fuels ============➔	All fossil fuels might be banned if GHGs suddenly increase 🡐============
LNG increasingly competing on price on spot basis ============➔	Renewables are "must take" so will displace fossil fuels 🡐============
CCS could be applied (at lower cost vs. coal fired stations) ============➔	Some policymakers seem to categorise gas as coal 🡐============
Uncertainties if new nuclear will deliver in time ============➔	Gas does not have a "voice" to promote itself[23] 🡐============
LNG has an excellent environmental and safety record ============➔	Significant numbers of "green" jobs have been promised 🡐============

LAST WORD: So – LNG is more than a transition fuel – it is here to stay till well beyond 2020 (and might still be relevant by 2050).

[23] Accepting the existence of Eurogas, but global LNG is absent