

Natural Gas: Bumpy Road to Global Markets

Turbulence before the Golden Age and Competitive Markets

- Commodities
- Global Natural Gas

- **The U.S. DOE's report, highly supportive of LNG exports, should pave the way for a rapid ramp up starting in 2015.** These exports will help global gas prices to converge, but only to a limited extent. We see little prospect of an international North American style shale gas revolution this decade, meaning that the high price of transporting LNG should keep regional price differences significant.
- **Fukushima jolted the global LNG market from a buyer's into a seller's market, mopping up the huge Qatari surplus capacity that emerged from declining demand in Europe and surging production in North America.** Exporters look likely to keep the upper hand until at least 2015, when a steep ramp up in new supplies, including US volumes, should put importers firmly in control. But even now virtually all the incremental supply to Japan and Korea is sold spot, with no sign that long-term contracts will fundamentally erode the current surge in spot sales.
- **The Qatari ramp up has been absorbed.** While buyers aren't keen to convert their current short-term supply terms into long-term contracts, market conditions look to keep spot prices close to oil linked levels for now. Even so, the LNG market is entering a period of benchmark diversification, setting the stage for a more gas-competitive market a half decade ahead.
- **The LNG markets at present look a lot like the oil markets in the mid-2000s, with demand surging globally, the global supply chain stretched and geopolitics providing bullish jolts.** Angola LNG is the only significant supply addition in 2013, while current suppliers including Algeria, Egypt, Yemen and Indonesia are struggling. Gas demand is rising, spurred on by low and capped prices in many regions and LNG import capacity grows, now spurred on by the rapid uptake of FSRUs, which cut the time and cost of adding LNG import capacity.
- **Structural factors are raising demand outside Europe, and the record divergence between oil and gas prices is now giving demand an additional boost.** Countries and companies look to bridge the arbitrage by replacing oil in transportation on road, rail and water, in industrial inputs, and in power generation.
- **But demand growth could be slower than expected by 2020 before accelerating afterwards.** European demand may stay weak, with Japanese demand flat-lining if not falling and Chinese demand growing modestly, offsetting the surge in the Mideast, Southeast Asia and South America.
- **When new supply surges from Australia and others, prices for spot LNG should come under pressure. If the full suite of currently proposed projects materializes that pressure could be severe.** Even before that the shift away from oil-linked to gas-hub based pricing in Europe should mean lower prices being paid for gas because of the gas-oil spread. Citi expects this spread to narrow.
- **Citi is bearish oil by 2020, expecting Brent prices to fall to \$80-90/bbl on oversupply, lowering oil linked LNG prices.** Spot gas prices outside of North America should face headwinds. Citi expects US spot gas at \$4 to 5, Europe at \$8-10 and Asia at \$11-14 as the arb from Henry Hub acts as a soft floor.

Anthony Yuen
+1-212-723-1477
anthony.yuen@citi.com

Seth M Kleinman
+44-20-7986-7084
seth.kleinman@citi.com

Edward L Morse
+1-212-723-3871
ed.morse@citi.com

Eric G Lee
+1-212-723-1474
eric.g.lee@citi.com

Daniel P Ahn
+1-212-723-3612
daniel.p.ahn@citi.com

Aakash Doshi
+1-212-723-3872
aakash.doshi@citi.com

With special thanks to Xing Xing and Shawn Shen.

See Appendix A-1 for Analyst Certification, Important Disclosures and non-US research analyst disclosures.

Citi Research is a division of Citigroup Global Markets Inc. (the "Firm"), which does and seeks to do business with companies covered in its research reports. As a result, investors should be aware that the Firm may have a conflict of interest that could affect the objectivity of this report. Investors should consider this report as only a single factor in making their investment decision.

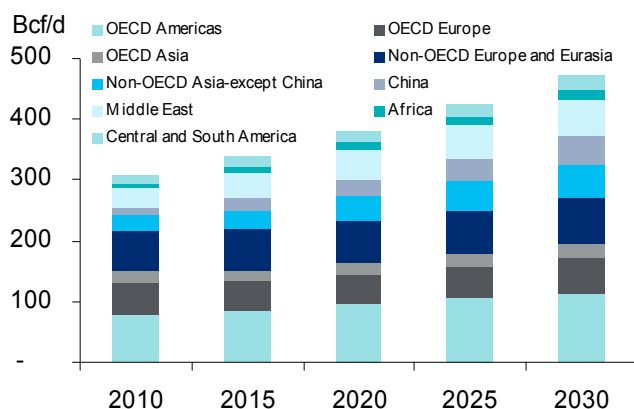
Contents

Turbulence before the Golden Age	3
The Evolution of the Pricing Debate	7
A Short History of Oil-Indexation	7
Why Oil-Indexation Remains in Place in Some Places	9
Oil-Indexation Can be Broken	11
Regional Trading Hubs with Potential	16
What Could Pricing Be in the Future?	16
The Effects of Low Henry Hub Gas Prices Are Already Felt	
Globally	18
Global Gas Model	20
Regional Possibilities and Challenges	22
Natural Gas for Oil Substitution	24
Europe	28
Japan	31
China	34
India	37
South Korea	38
South America	39
MENA Region	41
Australia	48
North America	50
Floating liquefaction, regasification and LNG tankers	60
International Shale	63
Appendix A-1	68

Turbulence before the Golden Age

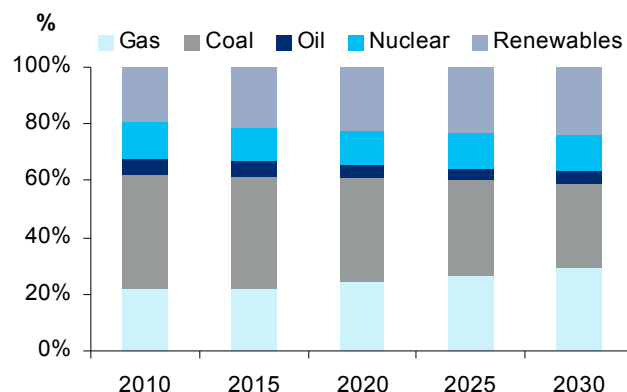
In this "Golden Age of Natural Gas", as the IEA has proclaimed, gas is expected to transform the global energy market, substitute for coal and oil in a number of sectors and locations, and open up new growth opportunities after major gas discoveries worldwide in recent years. These discoveries could lead to a surge in gas consumption, when previously the reliability, availability and cost of supply were concerns that hindered growth. Structural and policy-driven changes, partly a result of environmental concerns since gas is much cleaner burning than other fossil fuels and partly a result of fuel diversification should drive gas demand growth. The gaping divergence between oil and gas prices is also spurring conversions from oil to gas, particularly in both land and marine transport.

Figure 1. Global gas demand to surge in the coming decades



Source: BP, EIA, IEA, Citi Research

Figure 2. Share of gas-fired generation to climb due to fuel switching from coal and oil to gas in most places



Source: BP, EIA, IEA, Citi Research

Global demand is expected to rise from 310-Bcf/d in 2010 to 379-Bcf/d in 2020 and 469-Bcf/d in 2030, only lagging slightly behind supply growth forecasts. Middle East demand should continue rising on structural factors with an extra boost coming from gas for oil substitution in the power generation sector. Growing demand in South America and Southeast Asia turns these regions into gas importers. The strongest demand growth is expected to come from North America, which should also become self-sufficient. Besides environmental rules, low gas prices due to the shale gas revolution and associated gas production from oil and natural gas liquids drilling are causing a profound shift in energy demand, "repowering" America and revitalizing the industrial sector. Citi's "[Energy 2020 – North America, the New Middle East](#)" published on March 20, 2012, provides extensive coverage of this development.

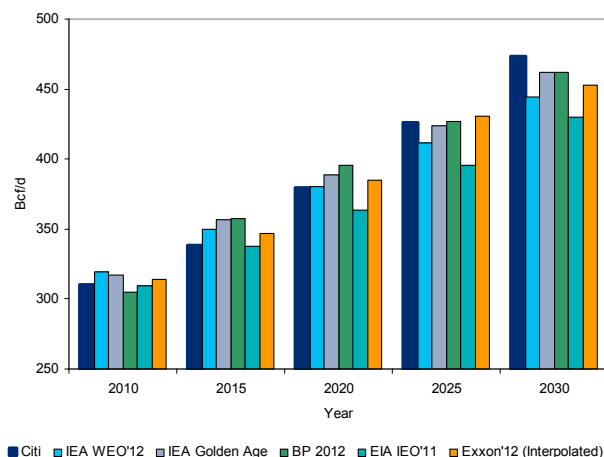
Figure 3. Conversion table

10-Bcm/year	=	0.97-Bcf/d
1-Bcf/d	=	10.3-Bcm/year
10-mtpa	=	1.3-Bcf/d
1-Bcf/d	=	7.7-mtpa

Source: Citi Research

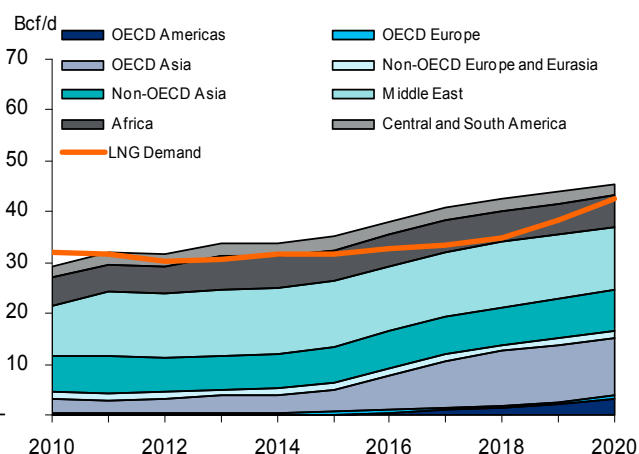
Citi's forecasts for total demand growth, however, are lower than some other estimates due to expected weak demand in some major consuming regions. Japanese demand is expected to flat-line or decline on lower electricity demand and possibly more nuclear restarts; European demand should stay weak, as gas prices remain too high to compete effectively with coal in the electricity generation sector, Chinese demand may not be growing as quickly as once thought.

Figure 4. World gas demand – comparisons across agencies



Source: BP, EIA, Exxon, IEA, Citi Research

Figure 5. World LNG demand and supply (if only existing facilities and projects current under construction go ahead, with none of the planned projects in whatever stages being constructed)



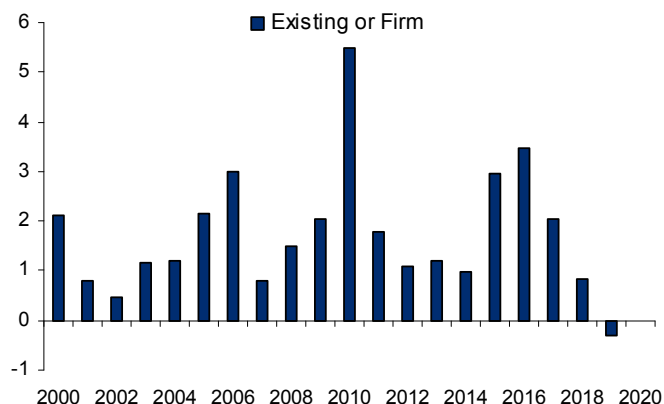
Source: Woodmac, Citi Research

A number of gas discoveries in recent years, as part of the overall hydrocarbon boom, should drive production growth for years to come, just as Liquefied Natural Gas (LNG) liquefaction is set to rise robustly as 7 world class Australian projects are expected to come online. Strong growth also is expected from North America, where production could rise by 20-25-Bcf/d between 2010 and 2020 from shale and associated gas production. This will likely turn the continental U.S. from a gas importer into a 5 to 8-Bcf/d or more LNG exporter by 2020. Australia in OECD Asia could replace Qatar as the largest LNG exporter in the world, but Middle Eastern production could surge as the region looks to replace oil with gas in power generation. East Africa's production could begin to rival Qatar and Australia in the years ahead. If Qatar begins to lose market share, the country could raise production through de-bottlenecking and the addition of new trains.

For the next couple of years incremental supply (liquefaction) is low. We have been bullish near-term LNG prices as set out in Citi's "[New Abnormal: 2013 Commodities Outlook](#)" publication, due to the low levels of new supplies, and the widely dispersed demand growth, now being given an additional boost by the increasing use of Floating Storage and Regas Units, vessels that let a country set up LNG import capacity offshore, a cheaper and quicker process than the usual onshore process.

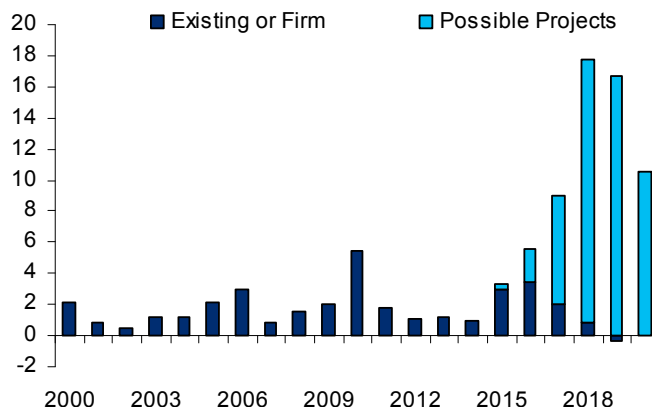
However, the current slate of possible supply projects clearly threatens to overwhelm demand if all of them are brought to market. There will need to be some rationing of potential supplies if an unprecedented glut is to be avoided. If this supply side deluge were to materialize there can be little doubt that current prices and pricing regimes would collapse.

Figure 6. Annual Incremental LNG Supplies – bcf/d



Source: Woodmac, Citi Research

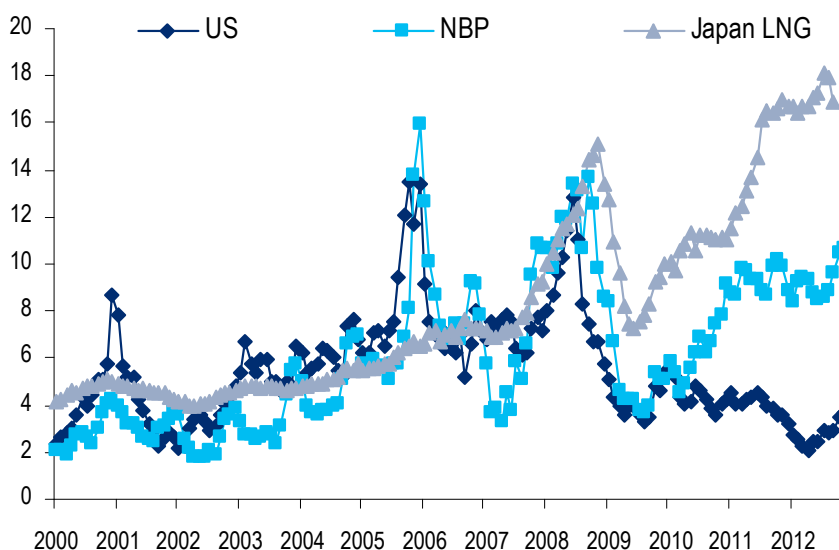
Figure 7. Annual Incremental LNG Supplies – bcf/d



Source: Woodmac, Citi Research

But how global gas should be priced is a contentious issue. Natural gas prices have historically been quite differentiated across the globe, largely due to the variety of countries' pricing mechanisms and the significant expense involved with transporting gas unless it is in a pipeline. Global LNG and European gas prices were indexed to crude oil and petroleum products, which do not reflect gas supply-demand fundamentals. But European gas prices have been based on multiple pricing arrangements for over a decade and now look set to move significantly away from oil product linkage, with 2013 being the year in which more than half of all gas in Europe is sold on a gas-hub, spot basis. In Asia, rumblings for change to their crude oil-linked pricing mechanism are brewing but the gas-oil spread is not as wide, as cheap alternatives to LNG are scarce.

Figure 8. Gas Prices In US, UK and Japan - \$/MMBtu



Source: Bloomberg, Citi Research

Geopolitics could be redrawn as gas supply increases, yet a gas cartel is unlikely to develop due to different strategic interests of major gas producers, such as Russia, Qatar, Australia and the US, and more importantly due to the integrated chain of many LNG supply arrangements. New discoveries away from the Middle East, Russia, and North and West Africa should give import nations more options

This report examines how global gas pricing could evolve, positing that, with the near-term tightness in the LNG market, exporters should keep the upper hand until the second half of this decade, when a ramp up in new supplies, including US LNG exports, likely puts buyers more firmly in control. We undertake this analysis with a detailed examination of the global gas production and liquefaction supply-demand balance, as well as regional power supply-demand balances; gas demand for power generation should be the growth driver of gas demand.

The Evolution of the Pricing Debate

Dissatisfaction with gas prices indexed to oil has been brewing in gas importing countries. Why should gas still be indexed to oil when production costs are different and given that gas has its own supply-demand fundamentals? What's more, natural gas today is essentially a primary energy source for electricity generation while petroleum is essentially a transportation fuel and changes in each of these sectors are what would challenge the indexed linkage. High gas prices due to high oil prices could also slow the supposedly more rapid adoption of natural gas as a fuel source. Most exporters of gas, concerned about reduced revenue from a break in the oil price link, instead claim that the lack of liquidity and transparency of gas pricing make gas prices an unreliable indicator of market conditions. Prices can be prone to manipulation. But oil is globally traded, with price visibility and "certainty," which is particularly important when billions have to be spent on developing new fields and building liquefaction facilities. They also argue that long term contracts based on a clear benchmark are needed to underwrite expensive projects and that there is no reliable global benchmark other than oil.

A Short History of Oil-Indexation

There are two prevalent forms of oil indexation in global natural gas trade. Pipeline natural gas trade in Europe was structured around the costs of oil products at the burner tip in utilities and industry at a time when oil was a primary energy fuel in those sectors. At its origins, therefore, pipeline natural gas trade was based on a clear competitive fuels test. LNG on the other hand was from the outset of international trade linked to crude oil not at the burner tip but at the customs border of Japan, the first major international LNG buyer. There was no competitive fuels test at the burner tip, but rather the crude oil link was based on national security feelings.

Ironically, international pipeline trade in natural gas in Europe began with the export of town gas from Germany to the Netherlands. But petroleum product indexation arose when huge finds in the Netherlands led Dutch gas to be first marketed to neighboring Germany after the discovery of the super-giant Slochteren (Groningen) field in the late 1950s and early 1960s. Pricing decisions were made jointly by the government and the two major producing companies, Shell and what was later known as Exxon. This and other subsequent gas sales by different exporters introduced three elements to pricing that over time lost their initial relationships to gas fundamentals: oil-indexation of prices, destination clauses and "take-or-pay" terms worked because natural gas was competing with fuel oil at the burner tip, as "take-or-pay" was required to finance pipelines, while destination clauses fit the perceived requirements of the companies on both the sell side in Netherlands and the buy side in the German market.

Historically, prices involved governments as well as companies. Pricing the gas became a question. While town gas, another commodity at the time, was priced using the cost-plus principle (where the delivered price is the sum of the production cost plus other costs associated with the delivery of gas and the profit margin), this system could not generate significant enough volumes because it was not based on end-user inter fuel competitive tests. Thus negotiations between companies and governments in the Netherlands and Germany – the intended market of Dutch gas – revolved around prices of other fuels in interfuel competition on the demand side. As gasoil was the fuel of choice in the consumer sector and heavy fuel oil was primarily used in the industrial and utility sectors, gas prices were pegged to prices of competing fuels, but the cost of transport, overheads and profit margins were

deducted at the point of sale, say the German Border. This form of pricing is called netback pricing, which facilitated burner tip competition for natural gas

But as gas sales spread to other regions, since different regions have different prices for fuels that compete with gas, netback prices at the Dutch border were different. Destination clauses were introduced to make sure that importing countries could not arbitrage their gas with each other, thus impeding the emergence of a spot market.

As the gas market expanded, long-distance transport of gas required substantial capital cost to build pipelines – or liquefaction facilities. To recover the capital cost, exporters implemented what had already been common in the huge North American natural gas markets, the “take-or-pay” system, or a minimum annual quantity of gas that an importer must take.

The European market was changed over time because a very different system arose in the United Kingdom as the result of huge natural gas discoveries and the marketing of gas by a large number of producing companies. Over time, the combination of a large number of buyers and a large number of sellers was reinforced with the break-up of the British Gas monopoly and gas-on-gas competition ruled the regime in the UK. The inauguration of the Interconnector pipeline to the continent in 1998 initially brought surplus gas from Britain to Northwest Europe (the terminal on the Continent is at Zeebrugge), spreading spot sales and gas-on-gas competition to a pocket in Northwest Europe.

When it comes to LNG, global trade has similarly ironic beginnings. LNG was a made-in-the US invention (1914) and the first international LNG shipment came from Lake Charles, Louisiana and was shipped in 1959 to Canvey Island in the UK. Similarly the first major regular international trade came from stranded gas in Alaska and went to Japan starting in 1969. And Algeria started shipping LNG both to the UK and France even before that, starting in 1964, and then started shipping to Everett, Massachusetts in 1971. But the Asian trade that defines today's LNG market emerged in 1977 when Japan started importing from Indonesia (although the selling firm came from Houston). By 1984 Japanese buying based on the innovative pricing principles constituted more than 70% of global LNG trade.

The Asian LNG market was only superficially similar to the European market in that both have an oil link. But in the case of LNG in Asia, the link is to crude oil rather than to petroleum products and the link is at the import terminal rather than the burner tip. The pricing mechanism is what traders fondly call the Japanese Crude Cocktail (JCC), but it is really the Japanese Customs Clearing price, the weighted average monthly price of all crude oil imports into Japan as declared by the Japanese government. There are many factors that went into this price mechanism, virtually all of them idiosyncratically linked to Japan as well as to the next two large buyers of LNG, Korea and Taiwan. Japan had no indigenous crude oil supply, so there was no local competitive test; the Japanese end-user prices were highly regulated by government; and Japan was eager to diversify away from its dependence on oil imports as primary energy, given that these were highly concentrated in the Middle East. Thus the JCC emerged as a benchmark designed to pay a premium to exporters of natural gas in order to facilitate supply diversification (Japan simultaneously also underwrote the emergence of a large nuclear power sector).

Oil indexation worked well in both Europe and Asia for both pipeline and LNG until recent times. Assuming that oil prices might spike suddenly at times due to disruption and that they had an upward bias, the link – especially for LNG – grew to

have both lagged moving averages to protect consumers and ceiling and floor prices to protect both parties, so various softening elements were included in the pricing formulas, but no benchmarks were used that were based on gas supply-demand fundamentals. It is also the rigidity of this system that is bringing about its decline, faster with European pipeline than with Asian LNG, just as alternative ways of getting gas emerged.

Post 2008, there was significant downward pressure on prices, as demand sputtered and supply surged. In Europe, some LNG from Qatar started entering the arena, particularly in the UK, based on the NBP benchmark. Significantly higher volumes of LNG became available as the US market – once touted to be the emerging largest LNG import market in the world – began to rapidly rebalance as a result of the shale gas revolution; in 2007 some 3.5-BCF/d of natural gas was produced from shale and by 2010 the volume surged to 14.6-BCF/d, virtually erasing the need for any LNG imports into the US, which Qatar had geared up to supply. US shale production is approaching 25-BCF/D today, and US natural gas production has risen by some 10-BCF/d in the process. And then European demand plunged by due to recession.

Thus both European pipeline and waterborne LNG came under severe demand pressures at the same time. In Europe, Gazprom in particular, but other suppliers as well, came under pressure. Gazprom responded to pressures from its customers, who also were under pressure from regulatory authorities in the European Union, and postponed full take-or-pay requirements and increased the amount of pipeline gas that would be linked to spot rather than oil-linked prices. Simultaneously, the spot trading of gas became more dominant in Europe and spot LNG cargoes were made available in Asia and importers started to back off from signing long term oil-indexed contracts.

At the moment, European oil-linked prices remain under severe distress for three reasons: Gazprom appears to be losing its monopoly on Russian supplies; European gas prices are under pressure, not because of gas-on-gas competition but because gas is today priced so much higher than coal, which is globally abundant; and because the European Commission is enacting pro-competitive terms and forcing a de-bundling of integrated gas pricing terms. In Asia, on the other hand, the Fukushima disaster has forced the shutting in of all nuclear power plants in Japan, and utilities have had to buy up all available LNG, which otherwise would have been in surplus, in order to guarantee power to Japanese consumers.

Why Oil-Indexation Remains in Place in Some Places

Beyond the conditions that emerged after 2008, other factors tended to preserve oil-linked contractual arrangements. The length of contract and gas markets that were dominated by a few exporters had hindered this progress to market liberalization. Long term gas contracts signed in the past were usually 10 to 20 years in length. An annual “price review,” or contract re-opener is possible, which the European utilities have actively exploited in the last few years, but major exporters have been counting on their market power to resist the breaking of oil-indexation: Oil prices are high and spot gas prices are low, so that oil-indexed gas brings in more per unit revenue. Unlike North America, where there are numerous gas producers and suppliers, gas supply in Europe has been dominated by Russia, Norway, Algeria and Qatar. In Asia, Malaysia and Indonesia were key exporters in the past, but Qatar, with its mega trains of gas liquefaction facilities, has become the major LNG supplier to Asia Pacific nations and Europe.

Some major exporters also make the argument that the cost needed to bring on new LNG supply – a multiyear process – is high and therefore prices should stay indexed to oil, partly for the “certainty” of pricing. The average project takes 5 to 10 years from sanction to first gas. This, coupled with the low elasticity of supply and demand (once infrastructure is committed to gas there is limited flexibility), also gives the LNG market the makings of a very cyclical one. Fukushima kicked the market into a bullish phase, and this looks set to last another couple of years, but the surge in supply coming on stream in Australia, coupled with other smaller surges from elsewhere, threaten to push the market into an oversupplied, bearish phase later in this decade.

Meanwhile, the high costs of liquefying, transporting and regasifying gas as LNG are all pricey and are expected to stay so because of the energy-intensity of each process. This has meant that significant regional pricing divergences can persist, as has been the case among the US, Europe and Asia over the last few years. The friction in the market comes from transport costs. To illustrate, transporting a ton of coal from a mine in the US (e.g. Central Appalachia) to China's Qinhuangdao port costs about \$60/ton at present, or \$2.67/MMBtu; the cost of transporting a ton of oil is negligible; but a ton of LNG should cost between \$5 to 6/MMBtu to ship, including liquefaction, boil-off losses and regasification.

Stronger-than-expected demand growth and disappointing supply gains can keep global gas prices elevated in the short to medium term. Korea's current fragile nuclear situation, as well as demand growth in the Mideast, Southeast Asia and South America, can boost demand, but the economics of fuel switching elsewhere would slow oil- or coal-to gas substitution, limiting gains in consumption.

Globally, without significant new LNG supply coming online until 2015, prices could rise as demand rises. Angola has the only supply projects coming on line until Cheniere's Sabine Pass project in 2015. The Angola project is now expected to start supplying volumes in early 2013, a full year behind schedule. Meanwhile the list of supply sources with major issues includes Algeria, Egypt, Yemen and Indonesia. At this juncture the global LNG markets feel like the oil markets in the mid-2000s when geology and geopolitics caused supply disruptions and price spikes due to the very tightly stretched supply chains. 2012 is the first year in three decades in which LNG supply y-o-y has declined.

Amid these supply problems and rising demand, Qatar is also shipping more LNG cargoes to Asia and less to Europe, especially the UK. Qatar remains the largest LNG supplier to the UK. Lower LNG flow to UK boosts NBP prices because of the very limited supply options available – UK continental shelf production continues to fall. But higher NBP prices do not necessarily reflect stronger demand on the Continent. The situation is akin to the physical Brent oil supply dynamics in that the region is structurally short, so higher prices can reflect tightness elsewhere. UK demand should also increase next year on the UK carbon policy and LCPD (Large Combustion Plant Directive) that forces coal plants to retire.

An interesting development with implications for regional Asian pricing mechanisms is the start-up of LNG importing facilities in Indonesia and Malaysia, the 2nd and 3rd biggest LNG exporters in 2011. Both countries have import terminals starting up in 2013 and both have signed purchase agreements with oil-indexed pricing. It either demonstrates the comfort in the region with oil-indexation, or Indonesia and Malaysia simply want to preserve their own oil-indexed pricing regime for their exports, so as not to set a bad example.

Oil-Indexation Can be Broken

Breaking oil-indexation in the European and global liquefied natural gas (LNG) markets was once thought to be impossible, and many market participants hold tightly to this view. But spot gas pricing in the UK and continental Europe increasingly reflects the supply-demand fundamentals of gas, as oil-indexed gas continues to lose market share. In Asia, the latest deal signed by Kansai Electric with BP for 15 years, delivering 0.5-mtpa of LNG starting in 2017, is partially indexed to Henry Hub gas, not oil. Senior officials from major importing countries, including Japan and South Korea, gathered in Shanghai recently to discuss gas pricing and reinforced their position of growing resistance to oil-indexed prices.

Fukushima has delayed the inevitable fall of global gas prices as LNG demand has risen to replace nuclear generation. But for every demand jump comes more gas discoveries and the decline in gas prices looks set to resume by the latter half of this decade as supplies surge on the Australian ramp up. Japanese demand should moderate if and when nuclear restarts. The structural decline of LNG imports in the US and Europe also has steepened, with the US looking to export LNG and Europe recently diverting cargoes to Asia. High European gas prices slow economic growth and encourage fuel substitution away from gas. Expectations of strong gas demand growth globally is partially met with a slowing reliance on imports in some countries (eg. China) as domestic production increases.

Meanwhile, gas discoveries have surged in the last few years, making more supply available in the future. Liquefaction project delays only push back the increase in LNG supply, but the volume should still be available. Gazprom, the dominant Russian producer, has its finger in a rapidly weakening dike preserving an inevitably outmoded pricing mechanism at the cost of lost market share and lost revenues with an onslaught of enemies at the gates both at home and abroad. And Gazprom, for the first time, is now experiencing pressures that should make it lose its dual monopolies at home and abroad.

There are two necessary conditions for a move away from oil-indexation. The first condition is sufficient gas-on-gas competition to facilitate a market clearing price. This condition emerges with supply abundance. Europe meets this condition with its combination of pipeline and LNG supplies, weakened demand and competition on the supply side, particularly from Russia. The second condition is a means of price discovery, and here the rapidly increasing depth and liquidity visible in Europe's gas trading hubs are key.

Although it might take more time for oil-indexation to break in Asia, as prices of the majority of contracted supply to Asia is currently oil-linked, multiple factors, many simply due to loosening market fundamentals, are emerging that should break oil-indexation over time.

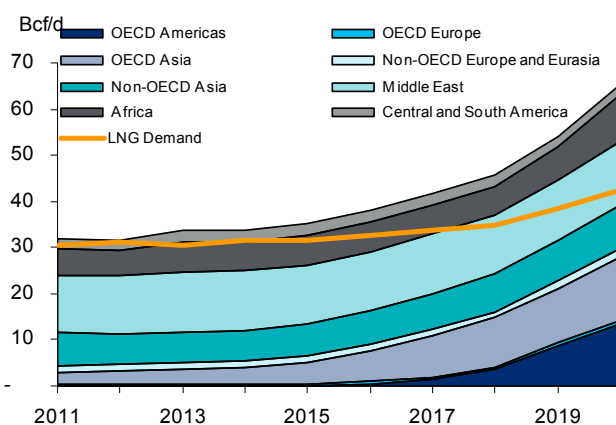
On the supply side, US LNG exports and the introduction of Henry Hub pricing, whose presence is already being felt globally through US coal exports, should finally bring gas-indexed pricing to the global market. The projection of US LNG supply is particularly poignant. At present, some 2-Bcf/d of LNG has been sanctioned in the US and the Cheniere Sabine Pass project looks to be in place by 2015. That's the equivalent of over 15-mtpa of LNG, a huge surge. We have projected that some 5- to 8-Bcf/d of US LNG is likely to be sanctioned. That's the equivalent of 38.5- to 61.6-mtpa of LNG, which would put US supply on a par with Qatar and Australia volumetrically and would all be based on Henry Hub gas prices, placing extraordinary pressure on oil-linked prices from elsewhere. What's more as has been seen in Europe, where European gas demand continues to fall, coal competitive prices can challenge gas's market share. This would mean that

liquefaction supply growth could outpace LNG demand growth, possibly causing a glut of LNG supply by 2016. Longer term, a surge in the discovery of gas reserves globally is expected to increase supply starting in less than five years.

On the demand side, conditions must be differentiated as between those in existing LNG buying countries and those in emerging LNG buyers. Among the former – Japan, Korea, Taiwan – there is a concerted effort to resist oil-indexed pricing, especially in Japan, which is bridging its gas supply gap post-Fukushima by buying spot and short-term LNG rather than signing long-term contracts. Japanese officials have made no secret of their desire for diversifying not only sources of supply but pricing mechanisms as well.

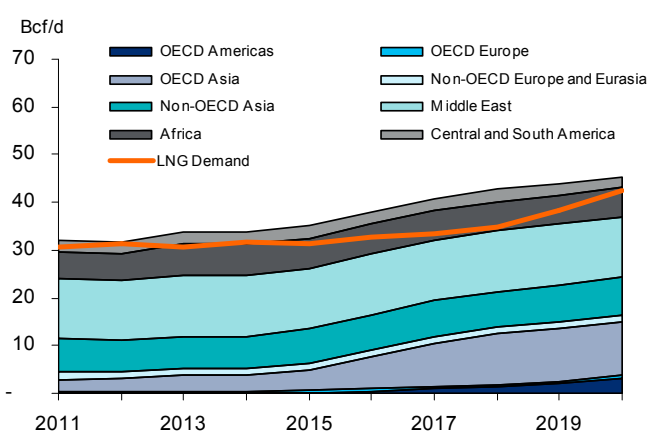
Among the newcomers, where there are domestic markets that help set acceptable price levels, there is great resistance to oil-linked contracts providing the base load of supply and a desire to eliminate them over time. In addition, demand factors are at work. Although gas demand growth is expected to be strong in China, the growth should be falling short of its ambitious goal of 26-Bcf/d by 2015, as indicated in the country's 12th five year plan. Instead, Chinese gas demand could reach 28-Bcf/d by 2020, with China largely having contracted its gas supply through 2020. Globally, although gas-fired generation as a share of electricity generation is rising, power demand growth in many locations is expected to slow due to a more challenging macro environment amid continued deleveraging and the increased use of efficiency measures. This should reduce the growth rate of gas demand. Japan's nuclear situation has limited scope to increase gas demand any further. It can only worsen again if the remaining two operating reactors are shut down, which, in exchange, would only account for a small amount of gas demand for gas-fired generation. But any future restart of nuclear reactors should only act to reduce gas demand, especially when power demand is encouraged and expected to fall.

Figure 9. World LNG demand and supply (if all projects go ahead)



Source: Platts, Woodmac, Citi Research

Figure 10. World LNG demand and supply (if only existing facilities and projects current under construction go ahead, with none of the planned projects in whatever stages being constructed)

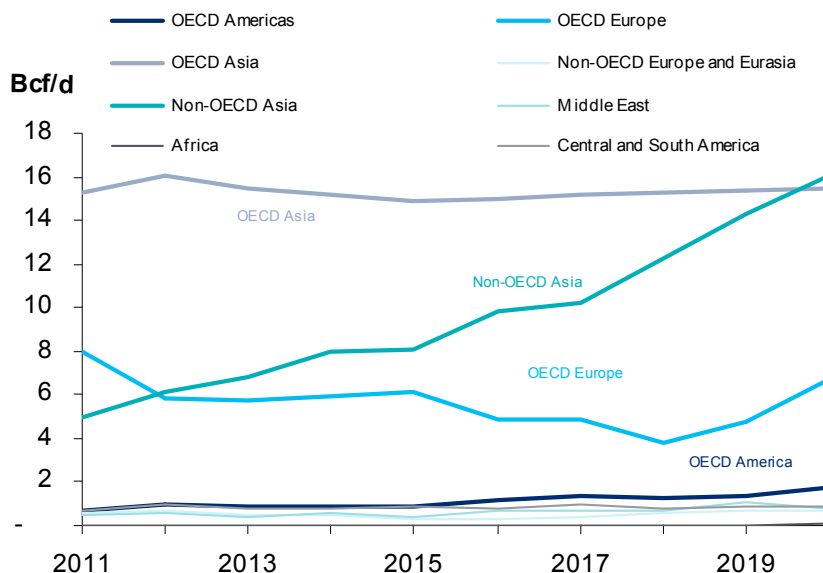


Source: Platts, Woodmac, Citi Research

However, this is not to say that gas demand won't grow. Opportunities exist for gas demand to rise either by taking market share away from oil or coal in the power generation sector, or through organic growth. But for gas to take market share away from oil, the economics have to be compelling. In the Middle East, oil is being replaced by gas as a power generation fuel because oil exports are more lucrative. In small countries such as those in the Caribbean, LNG could replace diesel and

fuel oil as a generation fuel, but again due to the more favorable economics of gas-fired generation over oil. We go into more detail on the various sectors with potential for gas to substitute for oil in a later section.

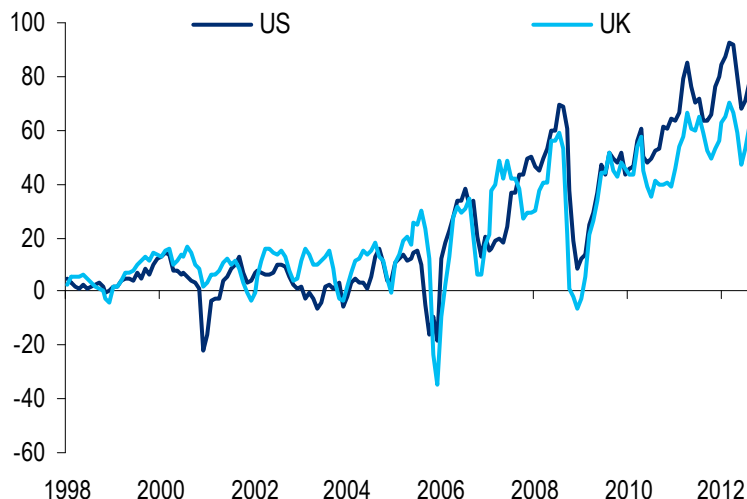
Figure 11. LNG demand by region



Source: Citi Research

Regionally, the trend of wholesale customers in Europe shifting their purchases away from oil-indexed prices to gas-exchange based pricing continues and 2013 may be a landmark year in which more than half of all gas purchased in Europe is on gas-exchange pricing terms. The pressure to move away from oil indexation has been driven by the record divergence between natural gas and oil prices and enabled by the increased depth and liquidity of the European gas markets which offer a means of price discovery.

Figure 12. Crude Oil – Spot Natural Gas: \$/bbl

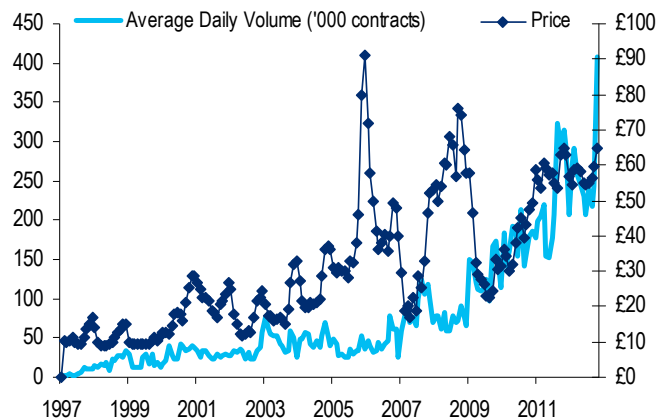


Source: Bloomberg, Citi Research

Russia's national gas giant Gazprom is struggling to preserve oil indexation on the continent but is coming under pressure from all sides and seems to be fighting a losing battle. In November 2012 Statoil signed a major supply deal with Wintershall (45 Bcm over 10 years) that is fully indexed to spot prices (the formula reportedly includes NBP, Germany's Gaspool and NGC and Holland's TTF pricing points). Novatek signed a supply deal with the German Utility EnBW in July 2012 to supply 1.9 Bcm p.a. for 10 years for gas to be sourced from European gas markets with hub-indexed pricing. And in September Gazprom itself agreed a supply deal with Centrica in the UK to sell 2.4 Bcm over 3 years starting in 2014 fully indexed to NBP.

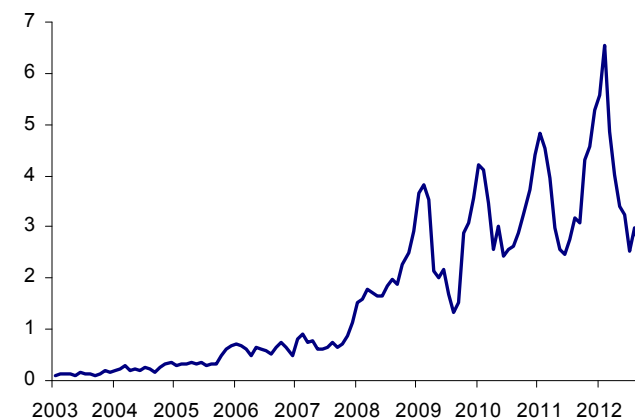
Complaints by end-users, the unbundling of EU contracts for natural gas (including the separation of production and transmission contracts) and the inexpensive competition from coal are all pressuring Gazprom in its European market, where Gazprom has lost a sizeable amount of its market share since 2008. Meanwhile, domestic and international competition from other gas producers, including Novatek, as well as from large oil companies with their associated gas are also reducing Gazprom's traditional freedoms at home and abroad. The antitrust action taken by the European Commission against Gazprom and the official inquiry by the European Commission's Directorate General for Competition (DGC) into Gazprom's allegedly anticompetitive practices are further indications of the pressures mounting on oil-indexation, which — along with destination clauses and a lack of 3rd party access to pipelines — is one of the key reasons given for the inquiry.

Figure 13. NBP prices and volumes



Source: Bloomberg, Citi Research

Figure 14. TTF Volumes (Bcf/d)



Source: Bloomberg, Citi Research

The situation in Asia is different, and looks set to remain so at least for the medium-term. In Europe the gas market was hit on both sides, with an economic recession damping demand while the shale gas story in the US released large volumes of flexible LNG cargoes from their planned US destination. This left the major wholesale buyers of gas with huge monetary losses on their term contract obligations. Asia on the other hand, has seen LNG demand surge in the aftermath of the Fukushima crisis, and in Japan, the world's biggest LNG buyer, the regulated utilities are able to pass on the higher costs of fuel to their retail customers. Japanese utilities are able to alter their gas and power tariffs in line with movements in the country's average LNG procurement costs, and if Japan decides to stick with its oil-indexed pricing system, other buyers in the region should have to follow suit if they want to secure supplies.

To date there is little gas-on-gas competition in the region, as the robust levels of LNG pricing continue to reflect. Even if the supply and demand fundamentals do introduce more slack to the gas system in Asia later in the decade, there is no robust mechanism for gas price formation. The problem begins at home in the markets where local output can compete with imports – India and China. But so far the lack of integrated domestic markets means that there is nothing other than political and regulatory weight against prevailing crude-oil linked LNG. Globally, the Intercontinental Exchange (ICE) introduced a swap future in October 2012 that settles against the Platts Japan/Korea marker (JKM) daily assessment (Bloomberg ticker: JKL1 comdty), but to date there has been one trade for one contract. The assessment itself is used for pricing spot cargoes of LNG into Asia and with Japan and Korea accounting for 47% of global LNG imports in 2011 the logic of using the marker for regional spot pricing is sound.

The Platts assessment has achieved some success, and is now estimated to be the pricing mechanism for 25-40% of spot LNG transactions in Asia, with spot deals accounting for roughly 20% of the global LNG market. A back of the envelope calculation indicates the JKM marker accounting for the pricing of ~10 Bcm or ~1-bcf/d of LNG sales. The JKM assessment has shown itself to reflect delivered spot LNG pricing to Japan, South Korea, Taiwan and China, and several new LNG projects have reportedly introduced the JKM as pricing bases – including Angola LNG and both Pluto and North West Shelf in Australia. Japan's Chubu Electric power company signed a purchase agreement to start in 2013 with BP Singapore with JKM spot prices reportedly accounting for up to 10% of supply volumes and Thailand's PTT in 2011 is reported to have signed a supply deal with Spain's Repsol using a formula of JKM +\$0.5/MMBtu. So the basis for a spot market marker is there and interest appears to be growing. Citibank is doing its part for the marker, and pioneered the settling of financial swaps against JKM, the first being done with an oil major in 2011 and several others have been settled by Citi since then.

Whether the world is awash with gas, future North American LNG exports are already giving importers price leverage and introducing more spot and swing supply. Its location enables it to be a swing supplier to Europe, South America and even Asia on differences in seasonal demand, while Asia benefits from gas supply indexed to gas prices. The US Gulf Coast should become a substantial global LNG hub, given its large storage capacity. Exports from the continental US should leverage off its Henry Hub pricing and are supported by prolific production in the US and Canada.

U.S. exports would undoubtedly impact prices, especially with today's high level of spot trading, and could limit oil-linked contract pricing to volumes only slightly above today's levels, likely capping global prices. Few of the current spot contracts would turn into long-term contracts linked to oil, as importers, such as Japan, are increasingly unwilling and have no incentives to convert gas procurement from spot to long-term contracts indexed to oil.

In particular, US LNG exports to Asia, with Henry Hub indexed-pricing, should further pressure oil indexation in the region. The volumes may not be huge, but they should put pressure on other suppliers looking to secure long-term contracts to be more flexible on pricing mechanisms. One possibility is to shift to a price indexed to Henry Hub with a large constant added on; this was the formula adopted by Argentina for its purchases.

Regional Trading Hubs with Potential

China is a significant natural gas producer with significant unconventional reserve potential; pipeline delivery from Turkmenistan and new pipelines are being constructed from Myanmar (with expected start up in 2H 2013), and is in negotiation with Russia for additional pipeline supplies. There are 5 LNG terminals in operation and an additional 5 under construction. A large number of buyers and sellers and substantial volumes are some of the prerequisites for a trading hub to turn into a robust price discovery mechanism, but the Chinese government's control of natural gas prices in the country is a major obstacle.

Singapore is starting up its first LNG terminal on Jurong Island in 1H2013, with the first cargo sourced from Qatar, and storage capacity is being built well above the import facilities operational requirements as the aim is to create a regional trading hub. Both Singapore and the JKM market bear watching as they are the best candidates for alternate pricing mechanisms, but for now there is no viable alternative to current pricing mechanisms. Korea, like Singapore, is also determined to establish a trading hub within its borders.

The U.S. Gulf Coast could similarly be a regional LNG trading hub serving Europe, South America and Asia. Asia is the prime market as gas prices are expected to remain higher than Europe and North America. Asian gas demand is also more volatile due to the lack of storage facilities. The growth of South America's gas demand is already drawing more LNG imports. But by being in the northern hemisphere with opposing seasons to the south, U.S. LNG can serve as a peak-shaving supplier to Latin America's winter gas demand, just as gas demand in the U.S. is lower in summer than in winter. Furthermore, Europe can still be short gas because more of the LNG cargoes could be diverted elsewhere, mostly Asia. U.S. LNG can fill the void in yet another peak-shaving role.

What Could Pricing Be in the Future?

Although pricing should remain differentiated in North America, Europe and Asia, their differences should increasingly narrow toward the level of inter-regional transport costs, particularly as spot trading increases, gas hubs develop and the US starts exporting LNG at gas-indexed Henry Hub-related prices. The rise of LNG trading hubs should raise the number of spot transactions. If and when supply exceeds demand, prices fall below "breakeven" prices for projects, as basic economics suggest that producers produce whenever prices are greater than the variable/operating cost of production.

Citi analysis points to a long-term natural gas price in the US of \$4-5, and this plus transport costs could act as a floor to the rest of the market. Transportation arbitrage economics translates this into European prices at \$8-10 and Asian prices at \$11-14. There may be periods of severe oversupply when prices are below these ranges, but given the need to sanction almost 2-Bcf/d of new projects to stop supply falling behind structurally rising demand, coupled with the importance placed on security of supply by many market participants, Citi expects the long-term cost of production to provide a high degree of support to prices.

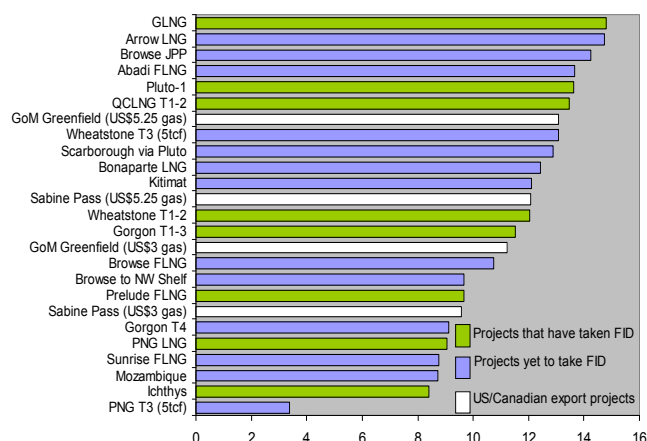
US Henry Hub prices plus shipping (HHS) could set a soft floor on Asian prices between \$11 and \$14. Nearly 5 to 6-Bcf/d of gas supply could come from the Continental U.S. by 2020, but they are viable only if destination prices are above sum of Henry Hub prices and the cost of liquefaction, shipping and regasification. As calculated in the U.S. section below, at \$4/MMBtu Henry Hub, the delivered cost of U.S. gas to Asia is about \$10; at \$6/MMBtu Henry Hub, the delivered cost in Asia should be \$12. If oil prices continue to stay above \$100/bbl, or \$16 to \$18/MMBtu

in oil-indexed gas prices, then the persistent gap in oil and LNG prices should continue to stroke the dissatisfaction of importers on the notion of oil-indexation. With the rise in LNG supply after 2015 while demand growth remains subdued, the pressure to adopt and increase a greater share of Henry Hub or other gas-price indices in LNG prices should grow. Prices could surge during peak demand seasons, since the lack of storage facilities accentuates the seasonality in prices. Oil prices could set a soft ceiling in prices due to the ability to fuel-switch from gas to oil at some peaking power plants. Prices could fall below the Henry-Hub-plus-shipping price floor in shoulder seasons, when demand is low and storage injection is not really possible.

This over-supply should challenge spot prices for LNG but should also further strain oil indexation as a basis for LNG pricing as sellers compete to maintain market share amidst falling prices. The large upfront costs required for LNG supply projects are sunk costs leaving the closest thing to a hard floor for prices to be provided by US exports, which at \$4 Henry Hub should land in Asia at ~\$10/MMBtu.

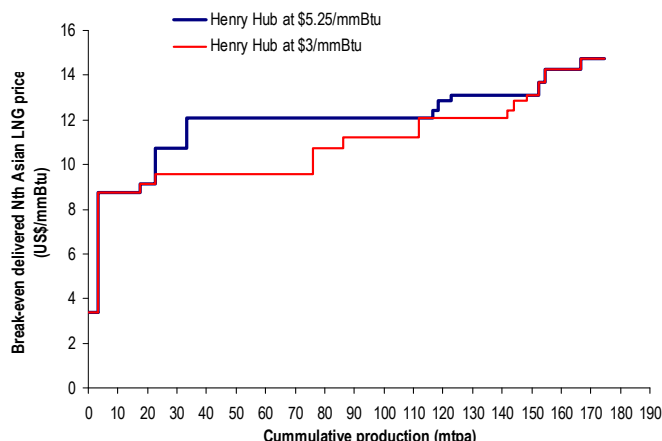
The charts below showing the breakeven prices required for the current slate of projects to provide a 12% IRR give a strong indication of long-term support from a cost of production standpoint at the \$11/mmBtu level (with Henry Hub at \$5.25).

Figure 15. Breakeven Delivered North-Asia LNG Price - \$/mmBtu



Source: Citi Research

Figure 16. Supply Curves With Henry Hub at \$5.25 and \$3/mmBtu



Source: Citi Research

Given the high proportion of projects that remain in the speculative category, and the high volume of supply that needs to be commissioned each year to meet rising demand and avoid a supply shortfall showing up in analysts' projections, coupled with the high priority given to security of supply, the costs of production support looks fairly robust, although markets' tendency to overshoot may result in periods below the \$11-14 range in Asia.

The mismatch between LNG supply and demand is being impacted by new floating technologies impacting the demand side of the equation but not yet the supply side. In 2008 the first floating storage and regasification unit (FSRU) started up in Argentina, this ship – which can receive LNG from a standard LNG carrier, and provide gas send-out through flexible risers and pipelines to shore – has now been followed globally. These vessels have allowed countries to quickly, and more cheaply, set up or ramp up LNG import capacity, with FSRUs now across a number of countries globally and more on order. The increase in demand from FSRU's has not been matched on the supply side as yet. The first floating LNG production

facility – bringing increased flexibility and lower costs to the supply side - is not scheduled to be on stream until 2017.

The Effects of Low Henry Hub Gas Prices Are Already Felt Globally

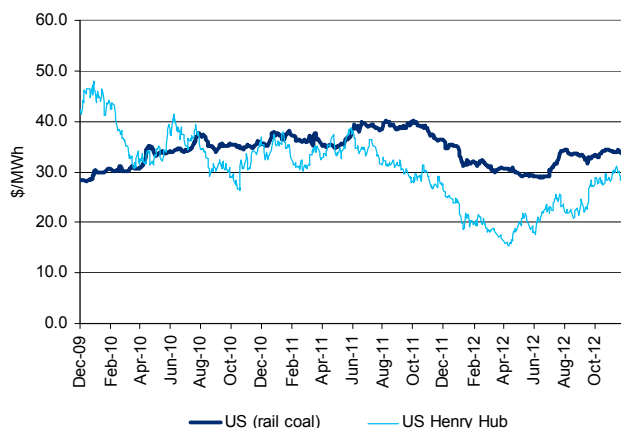
The US and Canada are already on a spot pricing basis. A growing amount of European gas is procured in the spot market, further reducing the demand of oil-indexed contract gas. Asian gas price gains could be reversed due to gas-indexed US exports, possible restart of some Japanese nuclear units and the reluctance of China and India, the two biggest growth countries, to accept steep oil-indexed prices.

The impact of US Henry Hub gas pricing has already been transmitted globally through three ways: an outright exports of US gas, exports of US coal and LNG diversions from the Atlantic Basin to elsewhere globally. First, US LNG exports linked to Henry Hub prices are certainly the most direct way of transmission.

Second, US coal exports are another way of transmitting Henry Hub pricing globally. With the shale gas production boom, thermal coal, particularly Eastern US Appalachian coal, is being displaced by natural gas in the power generation sector. US coal prices have similarly fallen as gas prices fell, but as US gas prices rose, coal prices also rose. Nonetheless, the excess coal is being exported to Europe but also in part to Asia, including China. The delivered cost of coal in Europe and Asia could effectively set a soft ceiling on coal prices, as the US is the swing thermal coal supplier globally. In places where coal and gas compete with each other in the power sector, lower coal prices make coal-fired generation more competitive, displacing gas-fired generation.

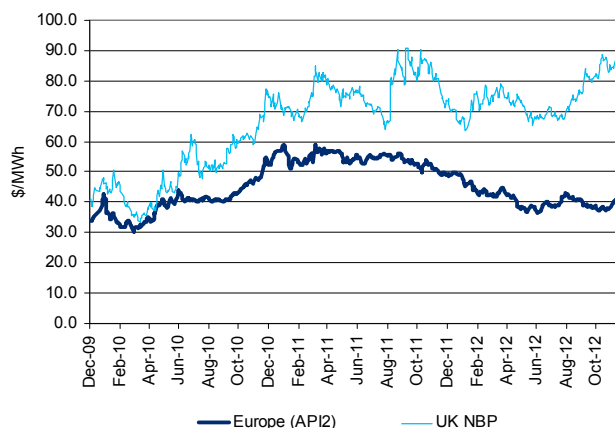
How competitive is US coal as a power generation fuel globally when FOB prices are in the \$50 to \$65 range? For Europe, with rail and freight transport costs around \$30/ton, the delivered cost of coal to Europe should be in the \$80 to \$95/ton range, after adjusting units of measurement and heat content. For a typical coal plant at 10 heat rate (or 34% efficiency), the marginal cost of generation should be in the mid-\$30/MWh to mid-\$40/MWh without carbon. In contrast, assuming an NBP price between \$8 to \$10/MMBtu, then an efficient gas-fired generation unit, typically a combined cycle gas turbine at 8 heat rate, would have a marginal cost of generation in the mid-\$60/MWh to \$80/MWh without carbon. Hence, European carbon price (EUA) would have to be in the mid-\$60/ton to make gas competitive with coal. The emission-adjusted generation cost would then be just over \$100/MWh. However, with the over-supply of carbon, emission allowance prices are below \$10/ton, far from enough to displace coal as a power generation fuel. If a gas power plant instead sources its gas from long term contracts tied to oil prices, then gas prices in the \$12 to \$14/MMBtu range would put a gas unit's marginal cost of generation between mid-\$90/MWh and mid-\$110/MWh, which is entirely not competitive at all.

Figure 17. Marginal generation costs of generic US East Coast coal (CSX rail) and gas (Henry Hub) power plants



Source: Platts, Citi Research

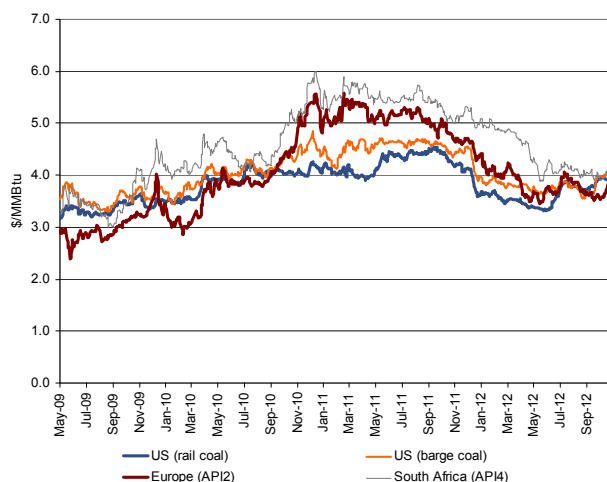
Figure 18. Marginal generation costs of generic European coal (API2) and gas (NBP) power plants



Source: Platts, Citi Research

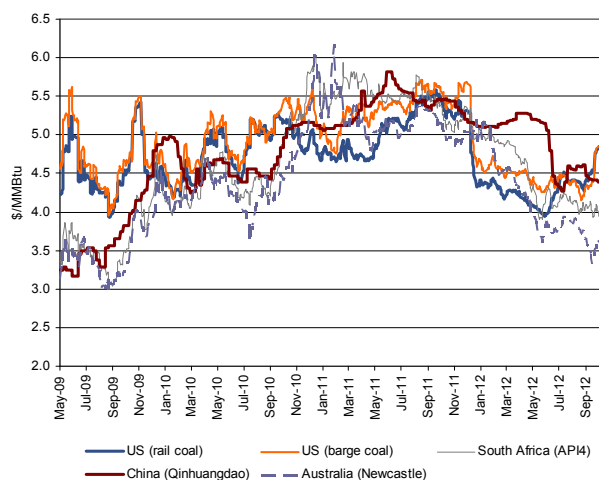
For Asia, with rail and freight transport costs between \$50 to \$60/ton, the delivered cost of US Central Appalachian coal to Asia should be in the \$110 to \$120/ton range, after adjusting units of measurement and heat content. Benchmark Asian coal prices, such as Australia's Newcastle 6,300 kcal/kg coal, have fallen to around or below \$100/ton from above \$120/ton FOB. With freight rates close to \$10/ton from Australia to Qinhuangdao, China, Australian coal delivered in China would be in the \$110/ton neighborhood, just lower than the delivered cost of US coal.

Figure 19. Costs of coal delivered to Rotterdam, Europe (heat content adjusted)



Source: Platts, Citi Research

Figure 20. Costs of coal delivered to Qinhuangdao, China (heat content adjusted)



Source: Platts, Citi Research

Third, the effect of Henry Hub pricing can be transmitted partially through LNG diversion away from North America and Europe. LNG liquefaction terminals that initially have the US market in mind, as the US was still perceived to be short gas supply up until 2008/9, instead have been delivering LNG cargoes to Europe and Asia. Before Fukushima tightened the global LNG market, excess cargoes had been pushing down prices, causing stress on oil-indexed pricing. Fukushima tightened the market, but low European demand from strong coal generation due in

part to US coal exports pressuring coal prices, as discussed above, reduces LNG demand. Cargoes were diverted to Asia from Europe. An increasing amount of diverted cargoes pushed down the Asian LNG price from a high in the \$18/MMBtu to \$13/MMBtu before recovering to the middle of this range as winter approached.

Global Gas Model

To quantitatively assess these factors and opportunities, the piece builds on two detailed global models on gas supply-demand and electricity supply-demand. On the demand side, we study energy policies, particularly in the electricity sector, of each major country or region, as gas demand for power generation is the key driver of gas demand growth. In the process, electricity, coal, nuclear, renewables and oil demand for power generation were also calculated for a more comprehensive picture of the market. This is then combined with a non-power gas demand estimates to come up with the total gas demand forecast. Combining this with the regional gas supply forecast gives insight into where and when LNG demand has upside or downside.

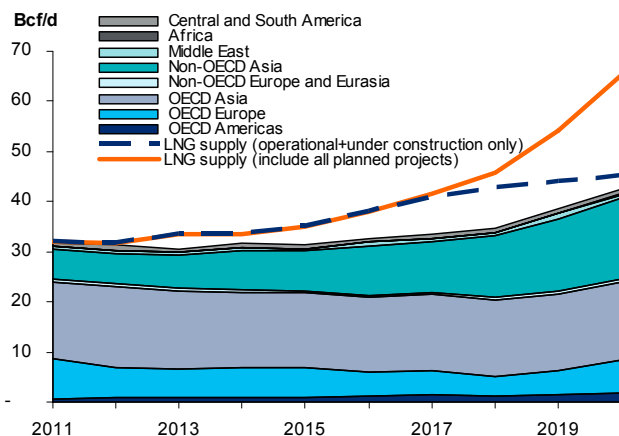
Net gas supply numbers were derived from examining individual liquefaction projects, major pipeline supply and production trajectories. We study the nameplate and effective capacities of each of the liquefaction facilities to come up with a global liquefaction supply projection. LNG demand is derived from backing out, from total consumption of a location, pipeline gas, domestic production and, if applicable, gas demand for LNG liquefaction.

Our global gas model - even using fairly bullish assumptions about demand and oil-substitution and risk-adjusting LNG supplies to reflect the industry's propensity to run behind schedule – still indicates an oversupplied market later in the decade. The surge in LNG supplies expected out of Australia, with other increases from the US, East Africa and Russia, all combine to more than satiate still rising demand.

LNG demand is a function of gas demand which (in addition to non-power gas demand, i.e. industrial demand) in turn is a function of total power demand and power supply from other sources.

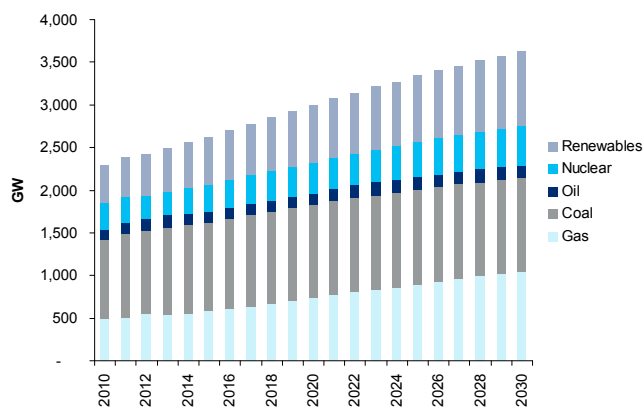
Over the long run, gas demand should experience very strong growth from now to 2030, driven in large part by gas demand for power generation. But near term demand growth is limited by the sharp decline in LNG imports from Europe, partly as a result of the high cost of gas losing market share to coal in power generation.

Figure 21. LNG supply vs. demand by region



Source: Citi Research

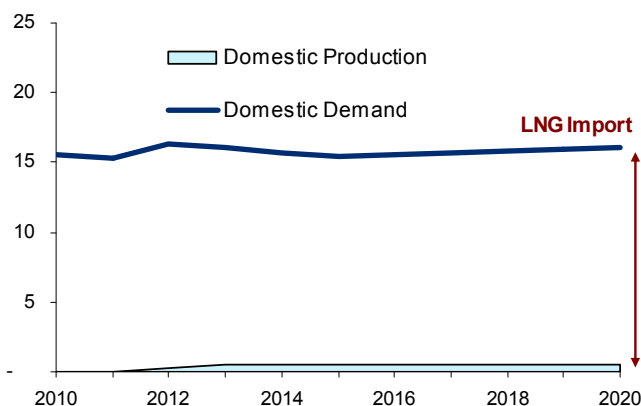
Figure 22. World Electricity Generation



Source: Citi Research

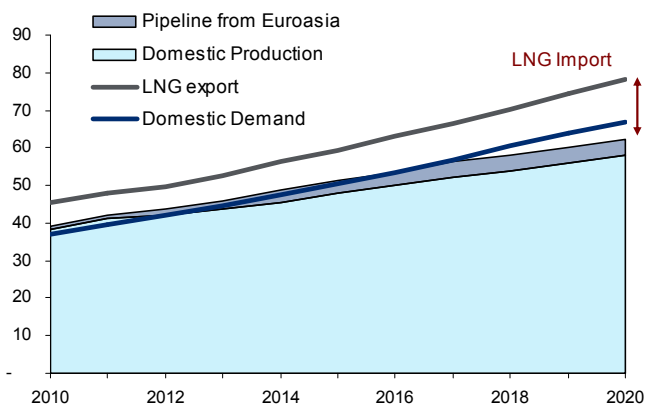
LNG demand in Japan should flat-line, if not fall, as more nuclear units come back online. For Korea, the energy policy laid out in the 5th Basic plan called for a reduction in gas-fired generation over the long term as well, but if the recently discovered nuclear cracks and other related issues were to worsen, gas demand should rise. How much non-OECD Asian demand will rise depends in part on how much demand growth there is in China and India. Although there is ample regas capacity in China, gas demand growth in China is also constrained by the availability of regional delivery options, such as pipelines, and local supply growth. Without supply, demand cannot grow. India's gas and LNG demand growth is expected to be strong, but it also depends in part on changes in domestic production and how the gas pricing system would evolve, with lower prices boosting demand as well.

Figure 23. Estimated Japan/Korea LNG Imports



Source: Citi Research

Figure 24. Estimated Non-OECD Asia gas balance and LNG imports



Source: Citi Research

We estimate that rising gas demand in the power sector does increase demand to 338-Bcf/d by 2015, 379-Bcf/d by 2020 and possibly 474-Bcf/d by 2030, but this is not as much as many LNG suppliers still project. Meanwhile, we examined the production side region by region, particularly taking a look at the known schedule of the coming global liquefaction boom

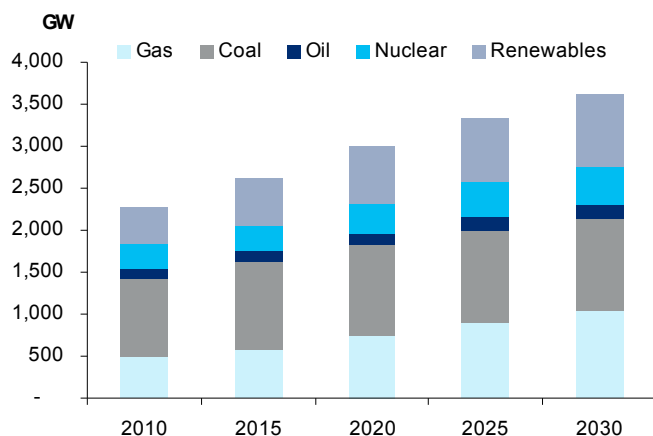
Regional Possibilities and Challenges

Overview

Global demand is expected to rise from 310-Bcf/d in 2010 to 338-Bcf/d in 2015, to 379-Bcf/d in 2020 and 474-Bcf/d in 2030. The strongest demand growth is expected to come from North America. Besides environmental rules, low gas prices due to the shale gas revolution and associated gas production from oil and natural gas liquids drilling are causing a profound shift in energy demand, “repowering” America and revitalizing the industrial sector. Citi’s [“Energy 2020 – North America, the New Middle East”](#) published on March 20, 2012, provides an extensive coverage of this development. Middle East demand should rise on its substitution of oil for power generation. Growing demand in South America and the Southeast Asia turns these regions into gas importers. But Japanese demand is expected to flat-line, as a possible return of nuclear generation amid lower power demand should reduce gas demand for power generation vs. 2012 level, but that demand from other sectors could grow. Chinese demand may not be growing as quickly as once thought. European demand should stay lackluster, as gas prices remain too high to compete effectively with coal in the electricity generation sector.

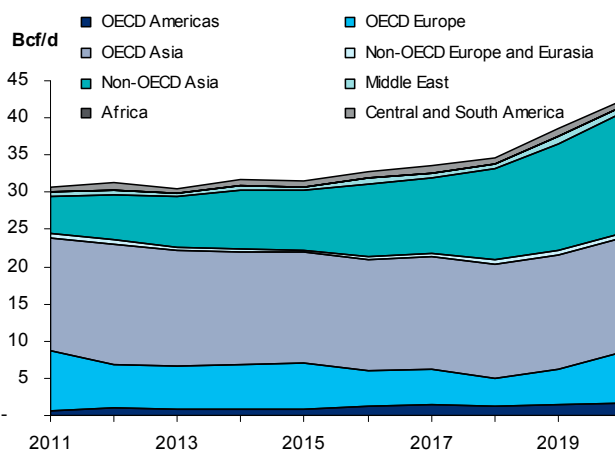
LNG demand could grow from around 31-Bcf/d to about 43-Bcf/d in 2020, lower than other outside estimates, just as about 65-Bcf/d of potential liquefaction capacity could be coming online by 2020 if all planned projects were to go ahead. There could still be about 45-Bcf/d of capacity available if only those already in operation or under construction were counted. Besides the now near non-existent LNG imports into Canada and the U.S., LNG demand should stay lackluster in Europe due to macro headwinds and gas-to-coal substitution in the power sector amid low carbon prices. While OECD Asia would likely remain the largest LNG importing region, the strongest growth could come from Non-OECD Asia ex-China, South America and, most prominently the Middle East, as it seeks to replace crude oil with gas in power generation.

Figure 25. World electricity demand growth



Source: Citi Research

Figure 26. World LNG demand growth by region



Source: Citi Research

The following sections will examine the emerging trends in:

- (1) Natural Gas for Oil Substitution
- (2) Europe and its challenges weighted down by high-priced oil-indexed gas
- (3) Japan and the impact of post-Fukushima energy policies
- (4) China and its desire for supply security – not necessarily through indiscriminate procurement of imports
- (5) India and its demand for imports amid hurdles from within
- (6) South America and its strong consumption growth despite a large resource endowment
- (7) The Middle East and Africa
- (8) Australia
- (9) North America and its role as the new Middle East?
- (10) Shipping and the floating liquefaction/regasification facilities (FLNGs and FSRUs) that are bringing producers and consumers closer together
- (11) International Shale - Can the magic in North America be replicated elsewhere?

Natural Gas for Oil Substitution

The divergence between oil and gas prices has been wide enough for long enough that many are now moving to capitalize on this. Some of these opportunities are on the supply side – with the Pearl GTL plant hitting full production in 2013, though it was commissioned back in 2004. The huge capital requirements and still unproven economics leave us skeptical that this technology will play a major role in bridging the price gap, however. The demand side of the equation, that is, substituting gas for oil, looks more promising and numerous efforts are already underway; given the size of the opportunity more should come.

The US, where natural gas prices collapsed to below \$2/MMBtu in early 2012 under the weight of the shale gas supply surge, has already seen action being taken by companies to capitalize on the spread in prices: Shell, FedEx, UPS and Waste Management have all announced measures to shift large parts or all of their heavy truck fleets to CNG and/or LNG.

Citi is now forecasting that as much as 30% of the US heavy truck fleet could shift to natural gas away from diesel by the end of the decade, substituting 3.6 Bcf/d of natural gas demand for 600-kb/d of diesel demand. Fuel economy mandates in the US give HDV manufacturers credits for alternative-fueled vehicles based on their greenhouse gas (GHG) emissions. Carbon emissions from natural gas vehicles are about one-third lower than their diesel-powered counterparts meaning that HDV manufacturers could meet their fuel economy standards by selling natural gas rather than diesel fuelled trucks. The major truck manufacturers are moving into NG HDVs, with Navistar planning to offer a full range of NG HDVs by the end of 2013. The cost differential for their long haul sleeper truck should be about \$70,000, so 70% higher than their current diesel equivalent, but the bulk of the cost differential is the LNG storage tanks – an area in which substantial reductions in costs are expected once economies of scale kick in. Refueling infrastructure is coming, with Shell announcing plans for 100 LNG filling stations along the US highway system and Clean Energy Fuels announcing plans for another 150 stations.

China is also undergoing the beginnings of a transformation to its trucking fleet with central and local governments encouraging the use of CNG and LNG for trucks in their gas producing regions in Xinjiang and areas around the Yangtze River Delta, which includes some significant population centers such as Shanghai.

Bunker fuel for shipping is another area in which natural gas is expected to make inroads into oil demand in the coming years. Saudi Basic Industries Corp just this quarter became the first chemical company to order transport carriers running on LNG. EU regulations that take effect on Jan 1 2015 should mandate sulfur reductions in marine fuel used in EU waters that will require either costly scrubbing equipment or very low sulfur fuel oil or marine diesel. LNG powered ships emit no sulfur and ~20% less carbon while maintaining a healthy running cost advantage, hence their appeal.

Lloyds Register in 2012 carried out a substantial analysis on the prospects for LNG as a bunkering fuel¹ and their conclusions are that in their base case by 2025 LNG demand for shipping would be 3.2 Bcf/d – equivalent to 0.6 -mb/d of oil demand, while their high case result found 8.7 Bcf/d of LNG used, backing out 1.6 -mb/d of oil demand.

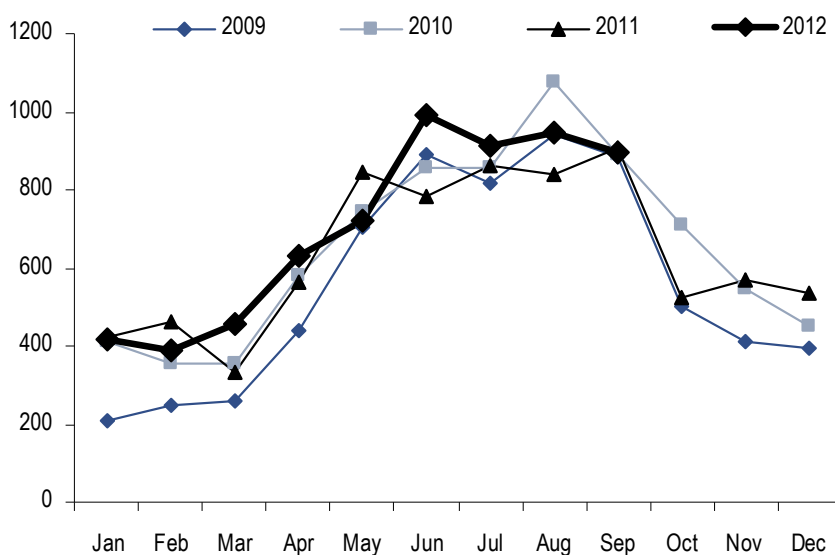
¹ http://www.lr.org/Images/LR%20bunkering%20study_Final%20for%20web_tcm155-243482.pdf

The tight/shale oil production process in the US is a very diesel-centric activity and producers have a robust economic incentive to shift to gas rather than diesel and this is gaining pace. EnCana estimates that producers in the US use 1.2 bn gallons of diesel each year for pressure pumping and another 1.6 bn gals is used to power the drilling rigs themselves according to Baker Hughes. This 180-kb/d of oil demand is probably the lowest hanging fruit and is not expected to be left hanging for long. One fracturing job can use as much as 185 bbls of diesel, with natural gas about \$2 cheaper on an energy equivalent basis to diesel, if a well has 30 fracks then switching to natural gas could save almost \$0.5m from the cost of the well.²

The petrochemicals industry is an area in which there is huge scope for substitution of natural gas for oil, and the volumes of oil consumed by the sector are significant. In 2011 global demand for naphtha was 5.9-mb/d and for LPG/ethane it was 10-mb/d. Much LPG demand is for transportation and heating, but if we assume that one-third of the IEA's reported LPG/ethane demand is for the petrochemical industry along with all of the naphtha demand that indicates that over 9-mb/d of oil demand or over 10% of global demand is under the beginnings of a siege.

The other area which has enormous potential for oil to gas substitution is in power generation in the Middle East. Saudi Arabia has been burning as much as 900-kb/d of crude and fuel oil for power generation in the summer, when demand is for power for air conditioning is at its peak. Kuwait and Iraq have also been burning substantial volumes as their power generation demand surge past their natural gas supply capacity. Saudi Arabia has turned its upstream focus firmly to gas to address its gas needs, partly because this should free up more oil to export. Over 1-mb/d or 5-Bcf/d of power generation demand in the Middle East in total can be switched to natural gas by the end of the decade. The charts below shows direct crude burn, with additional volumes of gasoil and fuel oil are also burnt for power generation purposes. The similar seasonality for gasoil demand to crude burn reflects the power generation impact.

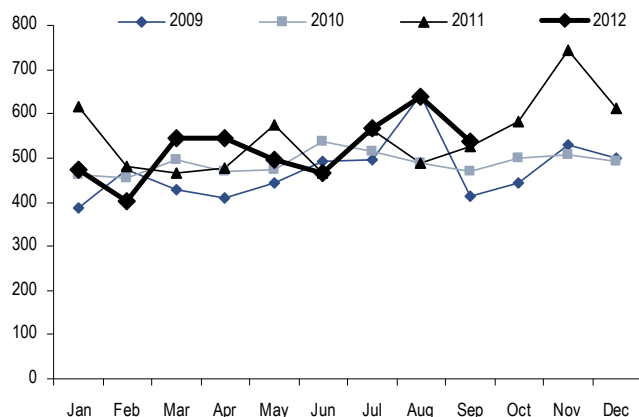
Figure 27. Saudi Arabia, UAE, Kuwait and Iraq Direct Crude Burn –kb/d



Source: JODI, Citi Research

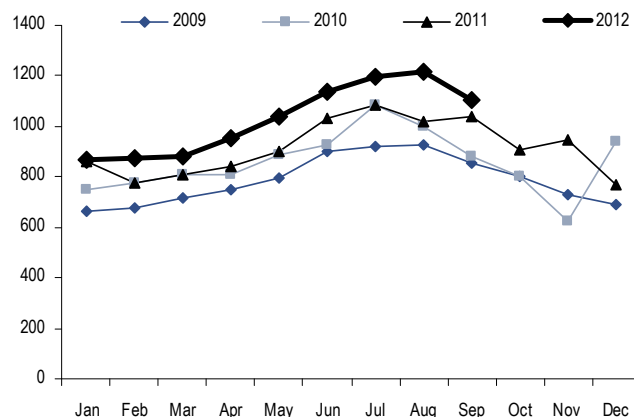
² <http://www.chron.com/business/article/Natural-gas-wins-place-as-oil-field-fuel-3900742.php>

Figure 28. Saudi Arabia, UAE, Kuwait and Iraq Fuel Oil Demand -kb/d



Source: Citi Research

Figure 29. Saudi Arabia, UAE, Kuwait and Iraq Gasoil Demand -kb/d



Source: Citi Research

The substitution of gas for oil is a contributing factor to our bearishness on longer-term oil prices. Citi is forecasting Brent at \$80-90/bbl with the risks to the downside. The key drivers of this bearishness are supply side factors - the ramp up in shale/tight oil production in the US and elsewhere by end decade, Iraqi production climbing rapidly over the coming years and deep and ultra-deep water production adding an incremental 3.5-mb/d to global supplies, a 50% increase from their current supply volumes.

Demand, however, is also in play as the fuel economy of US cars and trucks continues to improve and at end-August 2012 the Obama administration finalized fuel efficiency standards for US cars and light-duty trucks that mandates 54.5 mpg by Model Year 2025, which would more than double the fuel economy of new cars and light trucks from the October 2012 level – an all time high – of 24.1 mpg. China, Japan and Europe are all mandating significant improvements in LDV fuel economy.

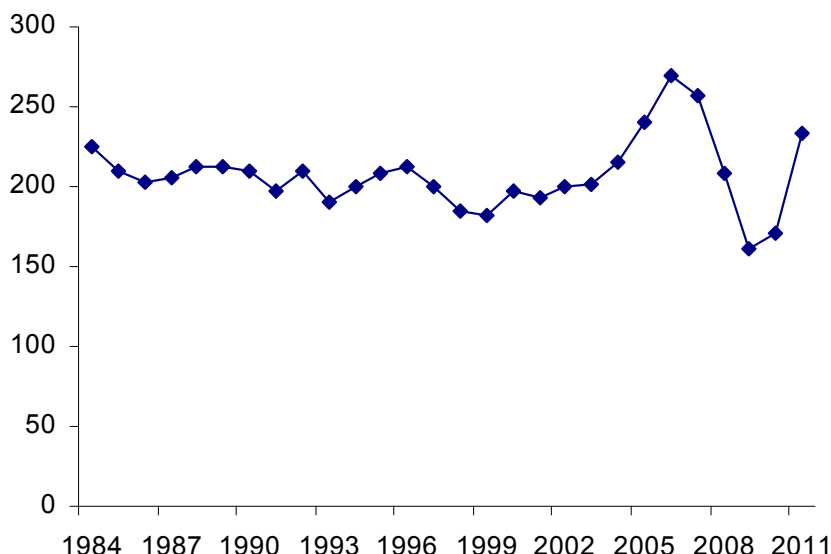
Transportation remains the one part of the energy complex in which oil reigns supreme as a fuel source, but that is now under attack from both sides. Demand is being reined in by much higher fuel economy mandates, and now natural gas is becoming an increasingly viable substitute and this should accelerate from here on out.

LNG for Railways

Railways are another mode of transportation in which natural gas is set to start displacing diesel in a transition similar to the shift from coal to oil decades ago.

The US, Canada, Russia and India are all starting to test LNG powered locomotives. The costs of modifying a diesel-electric locomotive to running on LNG reportedly run at \$600,000 to \$1m, but as one locomotive can burn 400,000 gallons of diesel in a year and on an energy equivalent basis natural gas is more than \$1/gal cheaper, payback periods can be quick. Both Caterpillar and engine manufacturer Westport have announced plans to make natural gas powered locomotives, albeit no formal timetables are available as of yet.

Figure 30. US Railroad Distillate Demand –kb/d



Source: EIA, Citi Research

Canadian diesel demand for powering railways is ~40-kb/d, in India it is ~50-kb/d. Canada is currently testing two LNG fuelled locomotives in northern Alberta. India is reportedly to tender for LNG powered trains, with Russia reportedly interested in supplying them. Russia itself is planning an LNG locomotive prototype that, if tests go well starting in 2013, should be followed by 39 more for delivery by 2020.

The last refuge of oil as a transportation fuel may be in the air, though even here Boeing has submitted a proposal for an LNG powered aircraft with a stretched fuselage that makes room for two LNG storage tanks. Safety and design issues should keep the plans purely theoretical for many years though, with 2040 being floated as a tentative timetable.

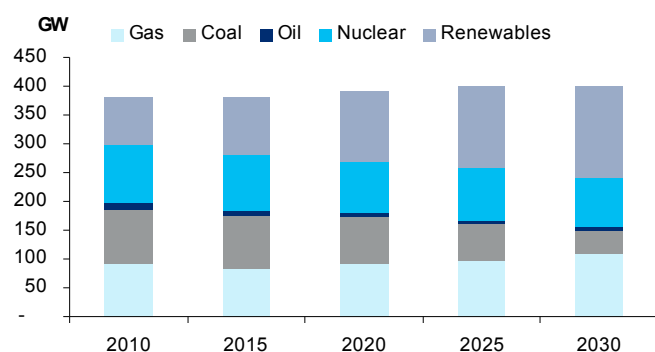
GTL

Transforming gas liquids fuel can be done, though it is expensive. Sasol's announcement that it is planning a 96kb/d GTL plant in Louisiana, that could come online in 2018, is yet another indication of how the huge spread between gas and oil is getting corporate attention. The \$21bn project will join a small group of others – a 32kb/d plant in Qatar, a 15-kb/d plant in Malaysia and Shell's 140-kb/d Pearl project in Qatar is reportedly running at full capacity.

Europe

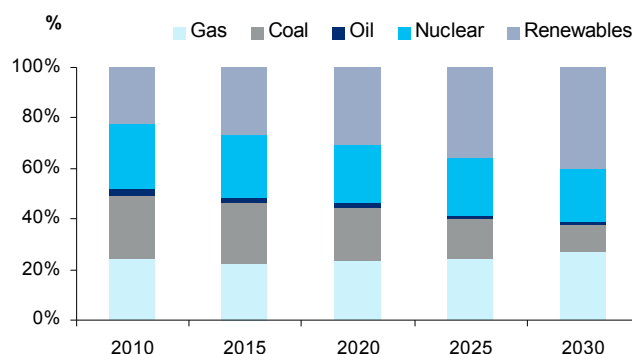
A secular decline in gas demand, particularly for power generation, is expected to pressure gas prices and erode the market share of oil-indexed gas. Just as major European utilities, amid mounting losses on purchases of oil-indexed gas, renegotiate oil-indexed pricing with Gazprom of Russia, Russia's rising gas production, government's revenue requirements and Gazprom's own struggle in the domestic market could prompt a trade-off between inevitably losing more external gas market shares and export revenues, or regaining market share by being more flexible in pricing.

Figure 31. Power generation by fuel in Europe



Source: Citi Research

Figure 32. Generation share by fuel in Europe



Source: Citi Research

Gas demand is squeezed in the power generation sector on low demand and strong output from other types of generation. Earlier in 2012, coal fired generation remained much more competitive vs. gas, particularly as API2 coal prices fell to the \$80s per metric ton from over \$100/mt in early April. Russian and US coal exports to Europe have kept the local market well-supplied. Combined with low carbon prices, coal has been much more competitive than gas in power generation. The share of renewable generation continues to climb. In future years, the Renewable Energy Directive will likely boost the share of renewable generation, despite the cost. Along with efficiency measures kicking in, especially under the Energy Efficiency Directive, these factors could cause persistent low gas demand.

Going forward, European gas demand is being squeezed on four fronts:

1. Generation from renewable sources, such as wind and solar, has been higher. The growth may slow, but German wind output rose 7% year-on-year in March, while solar rose 42% year-on-year.
2. The rise of coal-fired generation is expected to continue as a result of lower coal prices and low carbon prices. The rolling prompt API2 prices fell from the high-\$120/ton level in 2011 to as low as the low-\$80/ton, as the global demand for thermal coal softened and U.S. coal exports strengthened. The rolling prompt U.S. Central Appalachian coal fell from near \$80/short ton in 2011 to a low in the \$50/ton range before rising back to the \$60/ton neighborhood. Low U.S. gas prices and environmental rules should erode coal's market share in the country, leaving more for exports and transmitting low Henry Hub gas prices and U.S. coal prices globally.

3. Power demand remains lackluster on both weak macroeconomic conditions and efficiency gains. With current policies, the European Commission expects the EU to improve energy efficiency by 10%. In fact, International Power is set to close its 215-MW gas unit at Shotton.
4. High gas prices, likely on supply concerns and demand for storage injection, are putting heavy gas-consuming industrials at a particular disadvantage compared with their counterparts in the US benefiting from very low gas prices.

Power demand could rise very modestly as the economy improves after the recession. The shutdown of nuclear units in Germany should reduce nuclear's generation share in Europe from around 26% in 2010 to around 21% in 2030. Gas demand would have benefited and risen if not for more modest power and coal demand growth. As explained earlier, at current gas and coal prices, carbon prices would have to be above €60/ton for gas to be competitive with coal in the electricity generation sector. Carbon EUA prices are now in the single digits Euro per ton. Renewables would probably not grow to capture nearly 50% of the generation share by 2030, but more likely at 40% vs. 22% in 2010, due in part to diminishing fiscal support amid a weak macro environment. Fiscal issues and deleveraging are expected to last for years.

A modest recovery in seaborne coal prices, due in part to lower US coal exports on higher US gas prices, could make some European coal plants less competitive vs. gas. Along with coal plant retirements in the UK due to LCPD (Large Combustion Plant Directive), gas demand could see a slight recovery. Low carbon prices helped to keep coal power plants competitive. The European Commission is proposing to boost carbon prices through the process of "backloading" – withholding 400, 900 or 1200-mt of allowances in the nearby years and release them in the out years. While carbon prices did rise to €9/ton from a low of €6 earlier in 2012, they have now fallen back to near €7. Carbon prices would have to be in the €20 range to have more of an impact on coal-fired generation. If this "backloading" does not happen, carbon prices could stay in the \$6 to \$8 range.

To underscore the difficulty faced by gas-fired units in Europe, even those using the cheaper spot gas rather than contracted gas linked to oil prices, take the following two examples. Carbon prices would need to be between \$25 and \$50 for gas units to be competitive with coal. Carbon prices have been below \$10/ton in 2012.

- Case 1, suppose API2 coal prices were to stay in the \$100/ton neighborhood and NBP (and other Continental Europe spot gas) in the \$9/MMBtu range. The fuel-only marginal cost of generation should be around \$44/MWh for a generic coal unit at 10 heat rate (or 34% efficiency) vs. around \$72/MWh for a generic gas combined cycle unit at 8 heat rate. Carbon prices would need to be around \$50/ton for gas to be competitive with coal, where the marginal generation costs of gas and coal, with carbon, would be \$95/MWh.
- Case 2, suppose API2 coal prices were to rise to the \$110/ton neighborhood and NBP (and other Continental Europe spot gas) fall to the \$8/MMBtu range. The fuel-only marginal cost of generation should be around \$49/MWh for a generic coal unit at 10 heat rate vs. around \$64/MWh for a generic gas combined cycle unit at 8 heat rate. Carbon prices would need to be around \$27/ton for gas to be competitive with coal, where the marginal generation costs of gas and coal, with carbon, would be \$76/MWh.

Industrial gas demand faces headwinds from macro economic deterioration and high gas prices. Lingering Eurozone issues remain a drag on the industrial sector. Citi maintains a recessionary view on Europe for both 2012 and 2013. Ironically, a recovery of the Eurozone economy could lead to an appreciation of the Euro against other G10 crosses, which similarly hurts the competitiveness of industries. The high cost of gas also increases the input cost of fuel or feedstock. Europe's competitive advantage over North America in certain segments is being eroded, as the cost of gas in North America is priced off the \$2 to \$3/MMBtu Henry Hub gas, compared with \$8 or higher gas in Europe.

On the supply side, Gazprom will likely sell less gas in the home market, as competition inside Russia intensifies just as gas production is rising. Hence, Gazprom would have to stem its market share losses in Europe.

Longer term, Gazprom's settlements on pricing and gas delivery volume with a number of European utilities could signal the weakening of oil-indexation, but the preservation of partial oil-linkages can also be interpreted by some as the strength of Gazprom's bargaining power. On the one hand, oil-linkage appears weakened as a result of low gas demand and the spread of spot pricing, while Russian gas delivery to Europe continues to fall. Gazprom's concession could be seen as a sign of crumbling support for oil-indexation in Europe. Despite this, Gazprom managed to preserve the partial linkage between contracted gas price and oil amidst poor demand. It is possible that a new index element is included in the settlement with E.On. Based on statements from the head of Gazprom Export Alexander Medvedev, the latest deal with E.On, retroactive to December 2010, contained provisions that did not increase the weighting on spot gas, yet the rest of the pricing has been reduced and oil linkage preserved. While we believe that E.On likely did not agree to a reduction in the weights for spot gas, it is possible that a price index to coal has been introduced.

Gazprom's supply may not decline as much as previously thought. Russian producers are increasing output, with Novatek and Rosneft both boosting their supply to domestic users and intensifying the domestic competition within Russia. In addition, with more gas in Europe being priced and procured outside of oil-indexed contracts, Gazprom has lost significant market share and should be looking to stem further losses. The tradeoff between losing market share is a reduction in current oil-indexed prices. It had to renegotiate contracts with a number of major European utilities. In addition, the supposed gas shortage in February 2012 amid a severe cold snap raised questions on Gazprom's ability to deliver gas. As such, Gazprom may look to ship more gas to Europe, as it loses shares in the domestic market. It is also likely looking to improve its gas deliverability by shipping more gas to continental Europe or Ukraine for storage during the injection season, so that Gazprom can supply gas to customers faster. This should reduce the scarcity pricing during high demand periods. The price premium should fall.

Japan

The shutdown of nuclear that spurred the surge in LNG imports should gradually fade, as some nuclear units will likely restart in the longer term. The upcoming election could bring in a new administration that is more favorable to nuclear restart, also recognizing that a zero nuclear stance appears unsustainable. Longer term, gas demand is expected to stay flat, with lower power demand and some nuclear restarts reducing gas demand for power generation, offset by higher gas demand outside of the power sector.

The loss of Japanese nuclear triggered the sudden tightness in the global LNG market, but restarts of nuclear units provide marginal relief on demand. The first of two nuclear reactors in the Kansai electric area just restarted in early July, with the second unit about to restart later in July. Subsequently, there could be another 2 to 3 nuclear units coming back in about 3 to 6 months, likely a unit at Hokkaido Electric's Tomari complex and another at Shikoku Electric's Ikata complex. Restarts of another 2-3 units in the next 6 to 12 months could happen as well, depending on the state of government review and public opinion.

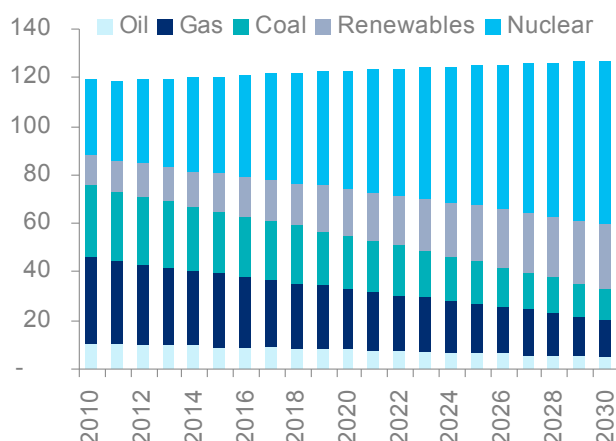
Before the nuclear shutdowns, Japan's 49-GW of nuclear capacity typically running at about 66-70% capacity factor effectively translated into about 32-GW of generation. If the 7% year-on-year decline in power load in the April to Dec'11 period, as reported by FEPC, due to conservation and/or demand destruction is maintained in 2012, then the 32-GW of replacement generation would be reduced by about 7-GW. Of the 25-GW that remains to be replaced, recent data suggested that coal-fired generation barely gained ground, leaving gas and oil-fired units for replacements.

However, some hurdles to future nuclear restarts in Japan are likely. Restarts of two reactors in Kansai Electric were done after they passed new guidelines on nuclear safety under a temporary oversight authority, in addition to the fact that nuclear generation used to account for over 50% of power supply in the Kansai Electric territory.

For future restarts, units would have to undergo reviews overseen by a new agency about to start in September. The agency should not be under the jurisdiction of the Ministry of Economy, Trade and Industry (METI), which holds a more favorable view of nuclear, but oversight should fall under the Ministry of the Environment. The new agency should still have to approve the new safety guidelines and approve any restarts after that. As such, the approval process could become more cumbersome and lengthy. Even though nuclear might restart in Japan, only a very small portion of the 48-GW of capacity could come back online. The impact on gas could be small: A 1-GW increase in nuclear generation generally implies a decrease of 0.2-Bcf/d of gas demand. Using a standard LNG tanker, this implies about one fewer LNG tanker needed in every 14 days.

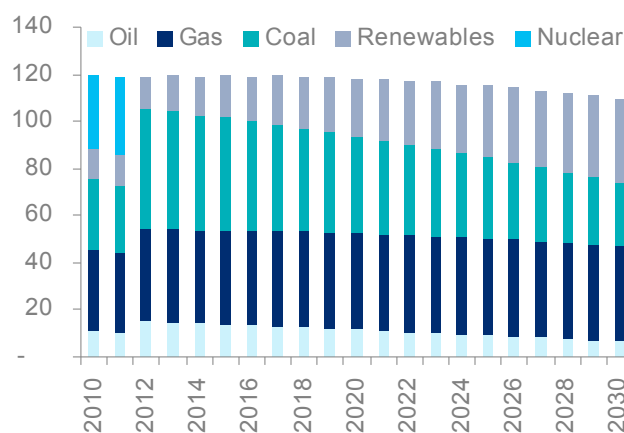
Longer term, unless massive infrastructure investment were to take place, the current gas and power transmission systems could restrict the fuel mix possibilities that Japan can pursue. Currently Japan still has to rely on oil-fired generation to fill part of the gap left by the loss of nuclear units, as a lack of infrastructure prevents gas-fired generation from fully substituting the loss of nuclear capacity. This should limit Japan's demand growth for LNG. The infrastructure issue mainly involves the lack of pipeline/storage network on the gas side, and the lack of connectivity of the power grid between the 10 utilities. Electricity frequencies are different from company to company. These issues should continue to limit the flexibility of energy supply, affect what and where power plants can be built, and influence how plants are connected.

Figure 33. Generation by fuel in Japan – base case before Fukushima



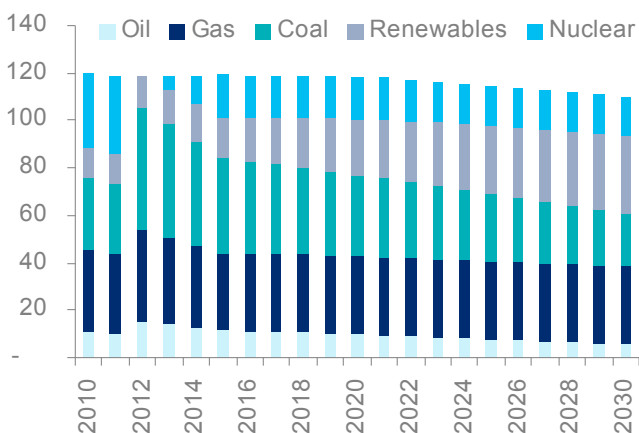
Source: Citi Research

Figure 34. Generation by fuel in Japan – 0% post-Fukushima



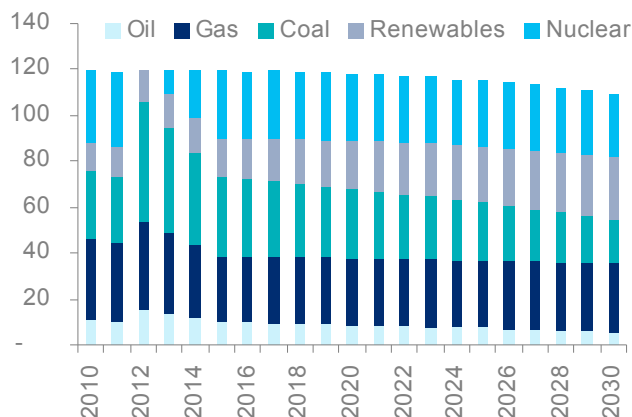
Source: Citi Research

Figure 35. Generation by fuel in Japan – 15% post-Fukushima



Source: Citi Research

Figure 36. Generation by fuel in Japan – 25% post-Fukushima



Source: Citi Research

Out of the three electricity scenarios outlined by the Institute of Energy Economics Japan (IEEJ), the 15% nuclear scenario appears to be more plausible and we use this as our base case. The 25% nuclear scenario should face the most opposition, as the public remains strongly opposed to nuclear. But with the 0% nuclear case a difficult proposition, the 15% nuclear option or a similar plan could become the compromise.

Figure 37. Japan Power Generation Scenarios

	2010	Possible New 2030 Scenarios			Original 2030 Energy Plan
	26%	0%	15%	20%-25%	53%
	Nuclear	Nuclear	Nuclear	Nuclear	Nuclear
Renewables	10%	30%-35%	30%	25%-30%	21%
Fossil Fuels	63%	65%-70%	55%	50%	26%
Oil	9%	6%	5%	5%	4%
Gas	29%	36%-38%	29%	26%	12%
Coal	25%	21%-28%	20%	17%	10%

Source: EIG, IEEJ, Citi Research

In all scenarios, power demand is expected to fall from 1.1-TWh in 2010, to about 1.0-TWh in 2030.

In the 15% nuclear case, total gas demand, including non-power gas demand, should reach 10-Bcf/d in 2015 but on a very gradual growth path as the non-power sector slowly increases its gas demand. The restart of nuclear units would increase nuclear's generation share from near 0 in 2012 back to 15%. Integrating renewables could be very challenging, despite the Feed-in-Tariffs that the government has introduced. The large footprint required of renewables is likely not capable to be fitted within the country's hilly landmass, besides the high cost of implementation.

Achieving a zero-nuclear option requires boosting renewables to between 30 and 35% of total power generation. The solar, wind and other renewable sources required would involve a staggering amount of investment and government support, given the high cost, placing a sharply higher fiscal burden on an already debt laden public sector. The pristine landscape in some parts of the country would likely become dotted with renewable generating facilities, as the limited landmass presents few options for locating these facilities.

The 25% nuclear scenario should face the most public opposition. As the previous dominance of a single political party has given way to a relatively more fragmented political landscape, pushing through a 25% scenario seems unlikely. Unless there is a sharp reversal in public opinion, even though the Fukushima accident is still fresh in the public's mind, this option does not appear to be viable.

China

China demand could reach 19-Bcf/d by 2015 and 28-Bcf/d by 2020, more modest than NDRC's³ goal. The total capacity of all regas terminals is high, potentially providing an upper bound to demand growth, with many provinces ready to start using gas as part of the energy mix. But infrastructure and supply availability are constraining local demand growth. Hence, China demand may not grow as strongly as once thought due to infrastructure issues, economic losses on imports due to regulated and low domestic pricing, macroeconomic headwinds and policy efforts.

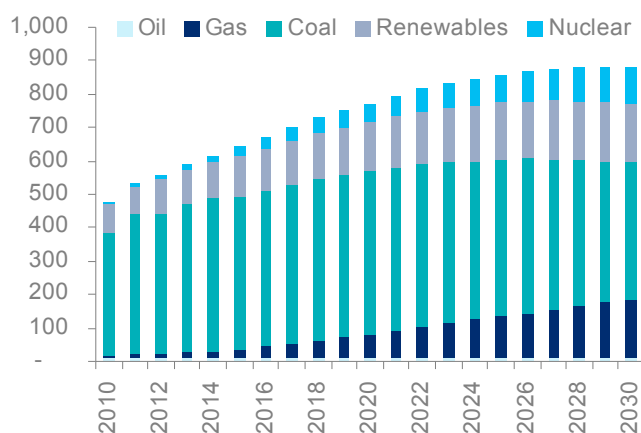
First, infrastructure still needs to be developed for gas to have a wider footprint for consumption. While heating is a major demand area elsewhere in the world, the heating system in parts of China is dominated by other means, with existing centralized infrastructure. Hence, the desire is not great to replace the existing system.

Second, massive losses incurred by PetroChina from gas imports have deterred the firm from signing more long term LNG contracts, so do other firms with regas terminals under construction. Unless the domestic gas price system is reformed and begins to reverse these losses, the prospect of signing long term deals is remote. Again, without gas supply, gas demand could not grow. The current price reform that is being experimented in the two southern provinces would effectively raise gas prices and slow down gas demand growth. This contrasts with the rest of the country, where gas is priced off wellhead production costs plus transport.

Third, Citi's economics team is expecting the economy to slow to the low-7% range in real GDP growth, in addition to a gradual migration from a more energy-intensive manufacturing economy to a more service, consumer-driven economy (a 'rebalancing'). Furthermore, while China needs to contract for pipeline gas from foreign sources and LNG to cover demand beyond what domestic production itself can provide, new demand projects can only emerge if the supply is available. Hence, slower growth in pipeline and LNG imports can effectively limit demand growth as well. How much demand would climb could depend on the growth of domestic production. Domestic production growth should be modest and unconventional gas will likely take time to develop, but both unconventional production and demand should accelerate after 2020.

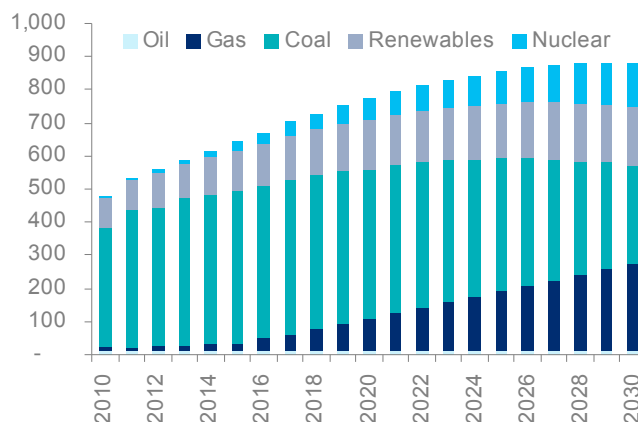
³ National Development and Reform Commission is a Chinese government agency that has broad control over the country's economic policies, including fuel prices.

Figure 38. Generation by Fuel in China



Source: Citi Research

Figure 39. Generation by Fuel in China – High Gas Case (25% by 2030)



Source: Citi Research

Hence, without the insatiable need for imports, China would be in a much better negotiating position with gas exporters – because the country doesn't need the extra gas. In fact, the country could be in an enviable position of having secured all of its gas supply until 2020, thereby lessening the need to negotiate with Russia on a new pipeline. It appears that China has secured about 4.9-Bcf/d in 2020 from liquefaction terminals that are current operating or under construction. The number could reach 5.6-Bcf/d if Memoranda of Understandings (MOUs) and Heads of Agreement (HOA) were included. Pipelines from Central Asia and Myanmar will likely provide at least 3.3-Bcf/d of gas in 2015 and perhaps 4.3-Bcf/d or more in 2020. Hence, with slower growing demand between 2010 and 2015, domestic production can ramp up gradually.

Unconventional gas development has been gradual. There exist a number of obstacles to shale gas development in China, some of which are familiar to many. Despite having an abundance of coal-bed methane (CBM), its development had been slow due to a number of institutional factors and misaligned policy incentives. Shale gas development in China faces the following issues:

- **Geology:** China does not have a long history of drilling activities across the nation, unlike decades of drilling in the U.S. The numerous core samples collected and studies conducted through drilling provided the U.S. an invaluable knowledge base of different geological formations.
- **Services sector:** The country prefers to develop its own services sector to develop unconventional resources. Only in certain situations, such as more technically challenging aspects, that the domestic service sector would outsource the work to major foreign services companies. But these few companies, such as Halliburton, Schlumberger and Baker Hughes, are also the ones with the most advanced technology, after drilling and servicing thousands of unconventional wells in the U.S. Their research divisions and overseas experience also allow them to innovate and accumulate experience.
- **Infrastructure:** Even with vast pipeline and gas processing network in the U.S., the midstream sector is still experiencing a boom due to the need to construct more takeaway capacity for the gas and oil produced outside of traditional producing regions. China has a much less developed infrastructure that the cost of production has to internalize the cost of building pipelines, so that the gas can

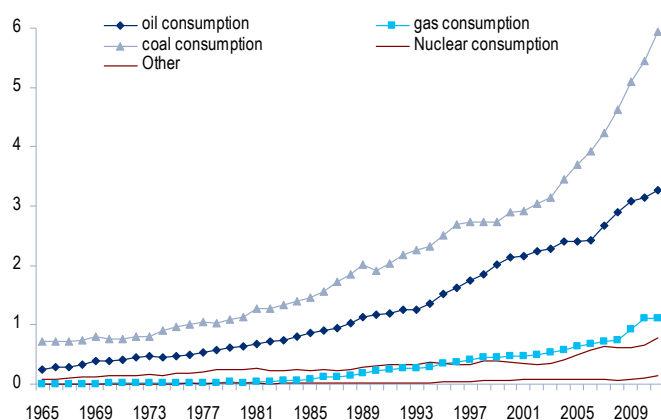
reach markets. Although the country has a history of building infrastructure at a rapid rate, having as developed a pipeline network as the U.S. should still take years.

- **Pricing:** The current gas pricing reform implemented in the two southern provinces, Guangdong and Guangxi, are meant to provide extra incentives for producers to explore and produce. This price reform links citygate prices in those two provinces with prices of fuel oil and liquefied petroleum gas (LPG) in Shanghai, but with a 10% discount to encourage gas demand. In the old system that applies to the rest of the country, prices are set based on a cost-plus system that adds transport costs on top of production costs + 10%. Gas prices in China differ across the country due to location and the producer supplying the gas. End-user prices are also regulated by the government. In fact, PetroChina loses money selling pipeline gas imported from Turkmenistan, as the regulated citygate prices are below the delivered cost of Central Asian gas, after including the pipeline transport costs. The new price reform should give producers greater incentives to produce and is set to expand to other provinces. Guangdong now has a citygate price of 2,740 Yuan/mcm (~\$12/MMBtu) and 2,570 Yuan/mcm (~\$11/MMBtu) in Guangxi.
- **An entrepreneurial independent exploration and production sector:** Even with more extensive geological records in the U.S., producers can still drill dry holes. The entrepreneurial spirit of independents in the U.S. allows them to try many different locations, formations and techniques in search of more oil and gas. Besides government research on shale development, George Mitchell, a pioneer of shale gas drilling, doggedly pursued shale development over more than two decades before succeeding in combining horizontal drilling and hydraulic fracturing for shale drilling. This is just an example of the type of experimentations needed in many aspects of exploration and production that China seems to lack. In the latest round in bidding for shale gas acreages in China, smaller companies and independents are finally allowed to participate, perhaps with the intension that these companies could engage in more experiments.
- **An active forward market:** While many producers in the U.S. are entrepreneurial, they are not entirely reckless and do hedge their activities. Producers in the U.S. and other developed markets are able to lay off their production risks in the forward market, but China does not have such a system.

India

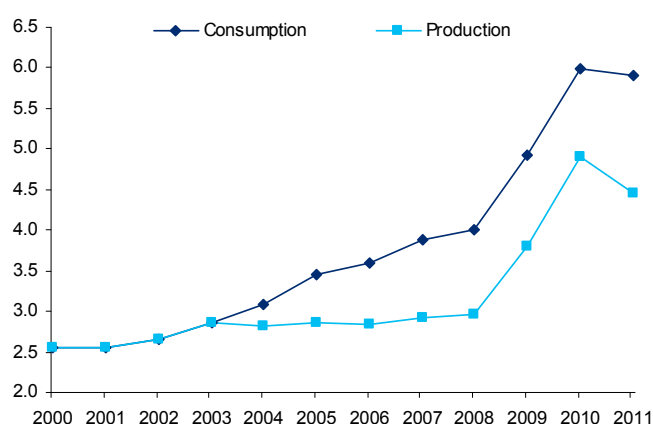
About 70% of consumption comes from the power and fertilizer sectors, which both have regulated prices as they are deemed strategic industries. This guarantee of cheap gas has driven demand upwards, eclipsing the country's indigenous production. Higher cost LNG has, however, found a market but only amongst a select group of enterprises that can afford the pricier input. A two-tier pricing system is therefore developing in India. There has been talk of gas pricing reform, and also of deregulating power prices – which would allow some pass through to consumers of higher cost inputs, but fertilizers are of such importance to India's rural poor that any proposal that would raise prices is unlikely to find much political support.

Figure 40. Primary energy demand – India



Source: BP, Citi Research

Figure 41. Gas demand and production – India



Source: BP, Citi Research

India has been working on making the TAPI (Turkmenistan-Afghanistan-Pakistan-India) pipeline project a reality for years, but the recent signing of a Gas-Supply purchase agreement is a sign of progress; media reports that the pricing may be ~\$13/MMBtu should keep LNG imports competitive. The current plan is for the pipeline to start up in 2018. India has been actively pursuing US LNG sources, and has shown interest in buying equity in the export terminals and shale gas assets in the US to hedge their price exposure.

The Indian government published a draft shale gas policy in summer 2012 with a first bid round planned for late 2012. There is shale gas production at present in India, but only from a pilot program, run by ONGC. The pricing of shale gas is a key concern, and is being debated in courts and various parts of the government. Other concerns such as building new infrastructure and clarifying land and water usage rights should also need addressing.

South Korea

Gas demand is forecast to rise at roughly 0.1-Bcf/d per year over the next decade, driven by the continued demand increase in the industrial and the residential-commercial sector. Gas demand growth in the power generation sector may be limited, unless the recently discovered nuclear issues worsen.

In the 5th Basic Plan, authored by the Ministry of Knowledge and Economy, on the future of the electricity sector, nuclear was supposed to expand from about 30% of generation as of 2010 to about 50% by 2024. Korean nuclear technology was supposed to play a dominant role, but recent safety and documentation issues, if proven to be much more serious, could cloud the future of nuclear. Given the already high utilization rates of coal-fired generation and limited scope for hydro generation to increase further, the generation burden will most likely fall on gas-fired generation.

If the recently discovered cracks in nuclear units and other related issues were to cause shutdowns of nuclear plants, South Korea would likely have to boost its coal and gas-fired generation. An expansion in the coal-fired capacity is already underway, but the increase may not be enough if the current nuclear development were to slow sharply or stop in an already tight generation market. Gas-fired generation has some spare capacity, given its relatively lower utilization rates, but LNG is also costly. A rapid expansion of gas-fired generation may be limited by infrastructure and cost issues.

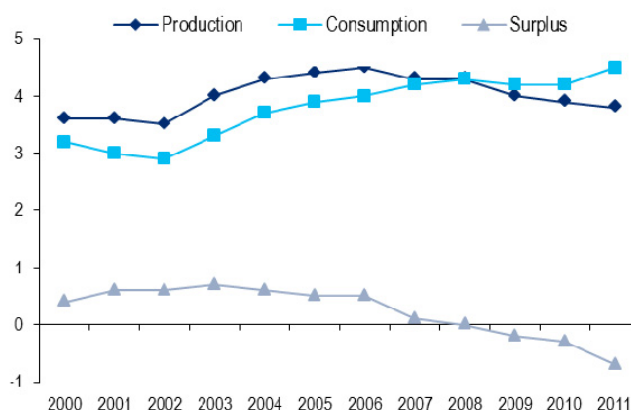
Korea's gas demand is highly seasonal, so the country often looks to the spot market for cargoes during peak demand periods, as the country has no gas storage other than LNG storage. Nearly 80% of gas demand comes from the residential-commercial and power generation sector, where demand from these sectors are highly temperature sensitive, especially in winter. U.S. LNG, once it comes to the market, could serve as peak-shaving supply and other purposes.

LNG should remain the sole source of gas supply, as proposals bringing pipeline gas to Korea face a number of hurdles. Offshore pipelines from Russia then via LNG or via China to South Korea have been discussed; so is the proposal to build an onshore pipeline via North Korea. For the onshore pipe in particular, the complex political calculus and security of supply should remain major obstacles for now. The changing landscape of U.S. LNG exports could have a large impact, as South Korea is a signatory of a Free Trade Agreement with the U.S.

South America

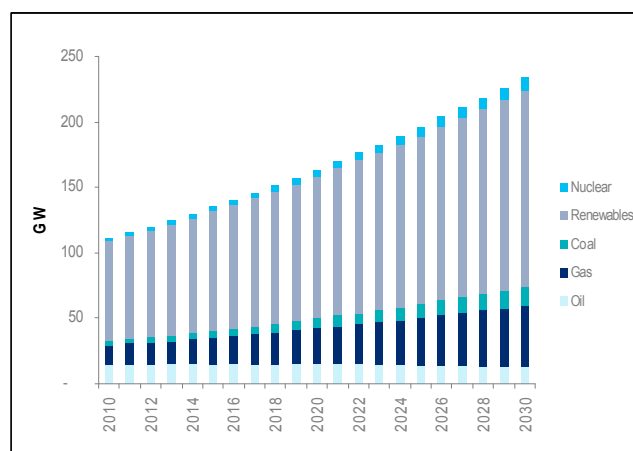
Gas demand in South America is expected to grow particularly as a power generation fuel. Despite vast resources, production has been coming on-stream only gradually. Low prices in Argentina both encourage demand growth but hold down production gains, leading the country to import more LNG. Proper gas pricing remains an issue that has seen the region experiences high demand growth but only modest production increases. Further, Brazil's LNG demand is highly variable due to its hydro situation every year. Although gas demand should continue to rise, new domestic gas fields could begin to supply more of the country's own demand. Coupled with the uncertainty on seasonal demand, Brazil should still prefer more temporary solutions to LNG imports, from using FSRUs to not committing to some long term oil-linked contracts.

Figure 42. Argentina Gas Balance



Source: BP, Citi Research

Figure 43. Power generation in South and Central America



Source: Citi Research

Brazil

Industrial uses now dominate local use of gas, but the growth of power generation demand is expected to boost gas consumption in the sector. As hydro generation serves the vast majority of the country's electricity consumption for now, changes in hydro levels quickly alter the demand for other fuels. Hence, LNG demand is highly variable.

But LNG demand should also be increasing over time on a weather-normalized basis, perhaps until Brazil develops its own recently discovered gas fields. Gas-fired generation now serves as a back-up to hydro generation but power demand growth is also leading to the need for more gas-fired generation. However, the lack of storage facilities prevents the country from importing gas when prices are lower outside of the summer and winter periods in both hemispheres.

On the supply side, piped gas supply from Bolivia should remain the baseload source, but recent domestic gas discoveries could add to production towards the end of the decade. Along with a more seasonal nature of gas demand for power generation, especially its dependence on hydro, Brazil should be more interested in flexibility rather than the rigidity in its LNG infrastructure builds and LNG procurement. FSRUs could continue to be the desirable choice for the country, where FSRUs serve all of Brazil's gas import terminals.

Argentina

After the debt crisis in 2001, among the measures by the government then to cushion the blow was the introduction of low gas prices. Prices at the well level ranges between \$2 to \$2.50/MMBtu but consumers typically pay in a similar range or lower, yet both piped and LNG imports are above \$10/MMBtu. The government has to cover the difference between import and consumer prices. Low prices spurred demand but curbed investment in the upstream sector for domestic production.

Demand growth out-pacing supply turned this once gas exporter to Uruguay, Brazil and Chile, now non-existent, into an LNG importer since 2008, with LNG regasification using FSRU (Floating Storage and Regasification Unit) at Bahia Blanca and Escobar. Other terminals are expected to come online, including the 3.8-mtpa GNL Puerto Cuatrerros possibly in 2013, though higher imports from Bolivia could leave this LNG project questionable for now. LNG imports are dominated by Trinidad gas from North America.

Similarly, U.S. LNG exports, as peak-shaving supply, could take advantage of contrasting seasonal demand between North and South America. Argentinian demand is highly seasonal, due mainly to the use of natural gas for power generation. Gas demand is typically highest in the middle of the year, with peak and trough monthly demand fluctuating between 3.5 and 4.5-Bcf/d. Argentina's demand seasonality is directly opposite to that of North America, where demand is at its highest usually from December to February.

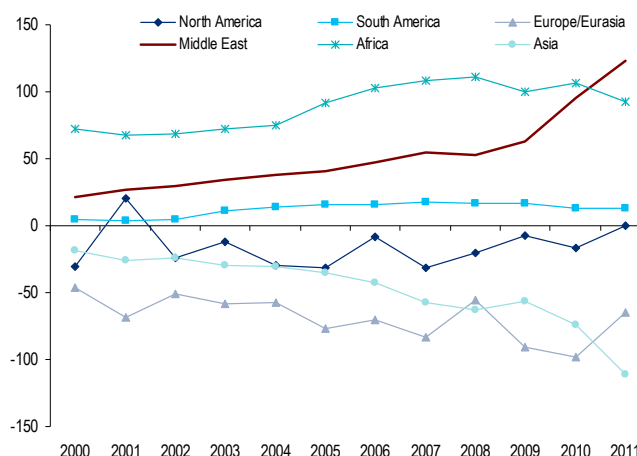
Power generation uses between 30 to 40% of gas demand, while the other 50% is almost equally split between the residential/commercial and industrial sectors. Natural gas vehicles use part of the remaining 10%.

Although it has a large endowment of hydrocarbon resources, including both shale gas and tight oil, further production growth does require further investment and technology, especially at unconventional fields. Yet, it nationalized YPF from Repsol, suggesting that the company did not invest enough, thereby causing domestic production to fall. Whether Argentina's LNG demand falls depends in large part to untapping these tremendous domestic resources. But with a history of heavy regulation and intervention, significant production growth out-pacing demand growth is less likely. The Gas Plus pricing introduced in 2008 to induce production growth has not reversed the decline in output.

MENA Region

The Middle East and Africa regions have the biggest gas surpluses in the world and are therefore the source so far of the majority of LNG, but change is afoot in the Middle East with export volumes set to fall as countries including Jordan, Lebanon, Egypt, Kuwait and UAE are all opening or expanding import capacity amidst surging demand for gas.

Figure 44. Regional Gas Surpluses (bcm/yr)



Source: BP Statistical Review, Citi Research

The Middle East and North Africa region remains home to a significant proportion of the world gas reserves, with reserve/production (R/P) ratios well north of 100 years not uncommon.

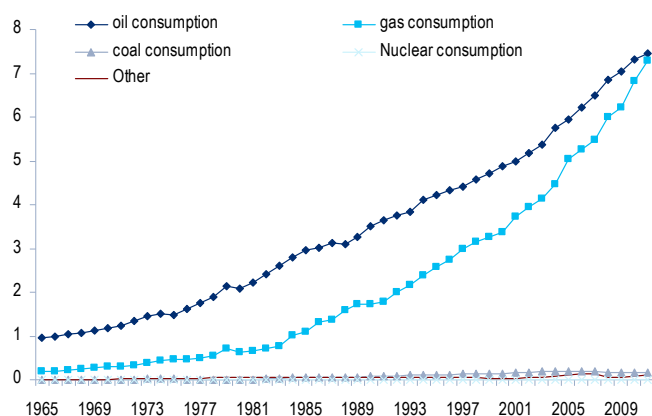
Figure 45. MENA Region Countries R/P Ratios

Country	R/P Ratio: Years
Bahrain	26.8
Iran	>100
Iraq	>100
Kuwait	>100
Oman	35.8
Qatar	>100
Saudi Arabia	82.1
Syria	34.3
United Arab Emirates	>100
Yemen	50.7
Other Middle East	49.3
Total Middle East	>100
Algeria	57.7
Egypt	35.7
Libya	>100
Nigeria	>100

Source: Citi Research

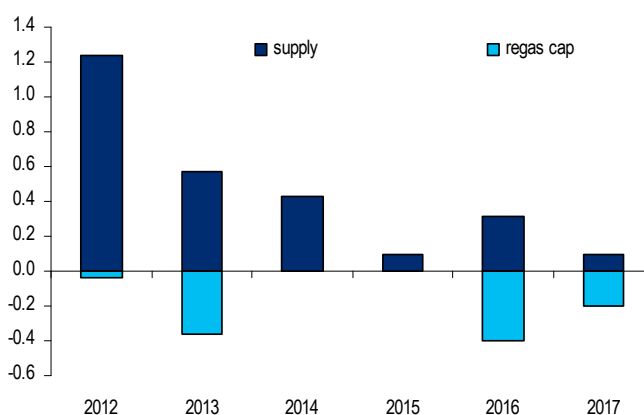
Despite these impressive statistics the region is becoming a bullish factor for global gas markets due to the relentless rise in demand. The key drivers of growth are surging power demand, subsidized and overcommitted supplies to industry and significant upstream reinjection requirements. In the Middle East in recent years, gas demand has been rising faster than oil demand, which itself has been soaring.

Figure 46. Middle East Energy Consumption By Fuel (mtoe/year)



Source: BP, Citi Research

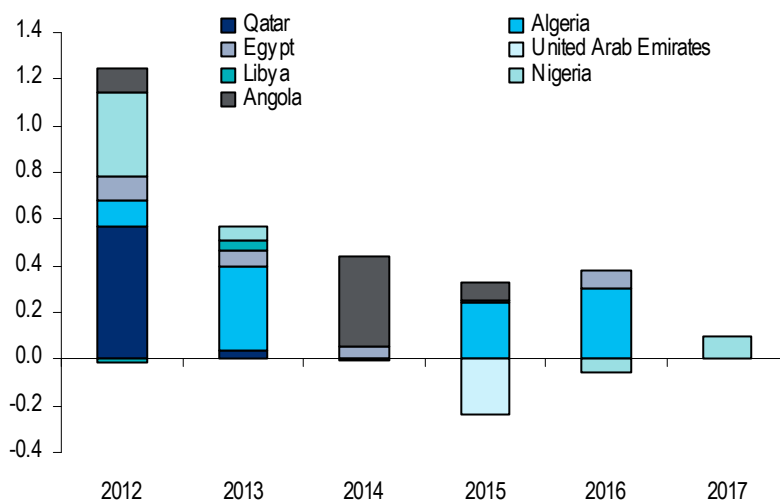
Figure 47. Liquefaction (Supply) and Regas (Demand) Balance



Source: Citi Research

Most countries in the region are pursuing gas-backed industrialization policies, even as allocation policies typically give the power sector top priority. The result is surging demand, though poor fiscal terms and low capped prices keep upstream developments on hold. This leads to a near-term need for LNG as a solution to gas shortages, with UAE, Bahrain, Kuwait and Israel all expected to start or ramp-up LNG imports over the next few years, turning the region into a bullish factor for the market.

Figure 48. Nameplate Gas into LNG by Country – Bcf/d



Source: Citi Research

A Look at Incremental Regional Supply

Angola LNG

Angola LNG, a 5.2-mtpa plant, was originally expected to start shipping cargoes in 1Q 2012, but is now expected to do so in 1Q 2013. This project was the second major LNG project expected in 2012, after Australia's Pluto started shipments in March, and was originally targeting the US but is reportedly now to be sold flexibly with first cargoes targeting Brazil and China.

The gas for the project is associated, meaning that if in the coming years Angola, as an OPEC member, is required to cut back on its oil production, its gas production could be affected. This uncertainty should curtail Angola from entering into long-term contracts for all of its gas.

Algeria

Algeria, one of the biggest gas exporters to Europe with three gas pipelines to Italy and Spain, was also the first LNG exporter in the world, starting back in 1964. Its options give it a choice of outlets for its gas. Algeria had two projects scheduled to start up in 2012, Skikda and Arzew. Skikda (4.7-mtpa) is now delayed until 2013 and this summer the Energy and Mines Minister stated that Arzew (4.5-mtpa) may not be fully online until 2015.

The combination of faltering production and demand rising by ~3% pa is eroding Algeria's surplus gas available for export. Domestic demand in 2011 took up 36% of Algeria's gas production, up from 25% a decade ago. The Energy Regulator CREG has forecast domestic demand absorbing 55% of current production by 2019 unless domestic subsidies are reduced.

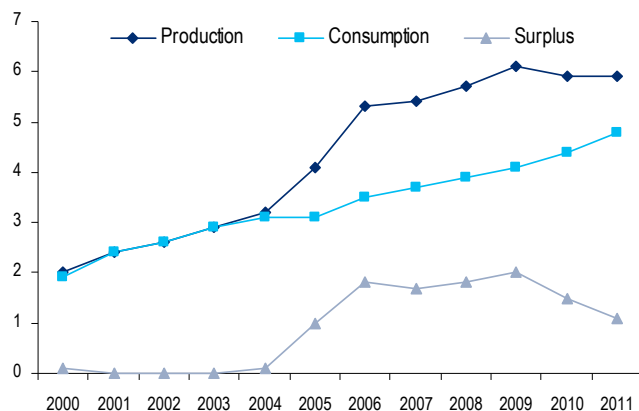
However, the gas rig count has been picking up over the last few years and new projects are underway, with the Ahnet tight gas scheduled to start in 2015, one of several projects in the southwest of the country under development.

Algeria has been talking up its shale potential and has held talks with several IOCs and independents with US shale experience. The country's hydrocarbon law is being amended with the specific aim of attracting companies, offering exploration periods of up to 30 years for shale oil and 40 years for shale gas. Public opinion could be a major obstacle, however, with concerns being raised in the media about the impact of fracking on water supplies – a particular concern in the region given how much of it is desert. The terms on offer to companies are much improved after the previous bid rounds failed, but the combination of public opinion and red tape may prove to be insurmountable obstacles.

Egypt

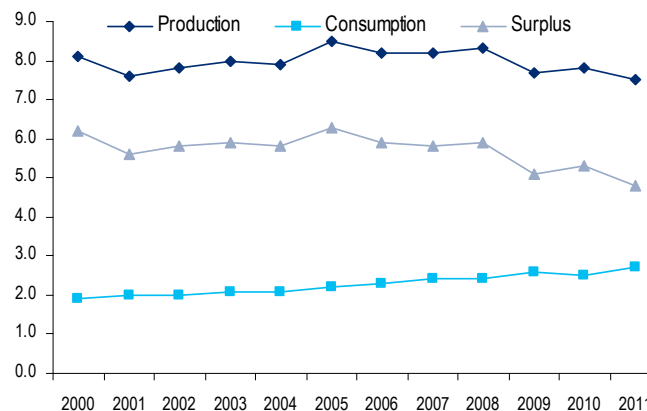
Egypt has seen an increase in LNG exports in 2012 as the production agreement for Abu Qir mandated the gas to be sold into the domestic market from 2009 to mid-2012, with an option to export kicking in this year. Egypt's net contribution to LNG markets is, however, turning increasingly bullish as can be seen by the recent tender to start importing LNG via a floating storage regas unit (FSRU) with a start up as early as May 2013. Egypt's gas demand for power generation has been growing at 8-10% pa with several new gas-fired units coming on line. Current talk is of gas imports of 500-MMcf/d being sourced from Qatar or possibly Algeria.

Figure 49. Egypt Gas Production and Consumption



Source: BP, Citi Research

Figure 50. Algeria Gas Production and Consumption



Source: BP, Citi Research

Jordan is joining the list of regional players importing gas, with the recent announcement that the terminal on the Red Sea port of Aqaba should open in mid-2014. Jordan was receiving gas from Egypt, but attacks on the pipeline – the same pipe taking gas to Israel – left Jordan using oil for power generation rather than gas

Qatar

Qatar's remarkable ramp-up since 1996 as been supplied by the North Field, the same field extends into Iran where it is known as South Pars. In 2005, the government of Qatar announced a moratorium on new projects to allow the North Field's performance to be evaluated once all the already approved projects were online. With the start-up of Qatargas IV – train 7 in 2011 - the final tranche of LNG supplies is now on line. The moratorium was expected to last just two years, but is now expected to last to at least 2014.

The results of the study on the North Field's performance should be the key determinant of further supply growth. If all is well studies of the potential for debottlenecking indicate an additional 14 mtpa of supply from the 6 megatrans is achievable. Beyond this it looks very unlikely that any additional capacity could be bought on before the end of the current decade if new projects were sanctioned after the study's conclusion in 2014.

The reliance in Europe on Qatari LNG supplies makes Qatar a key factor in price formation of natural gas in Europe. The diversion of Qatari cargoes to Japan post-Fukushima has been a supportive factor for European gas prices, and the commitment from Qatar to supply additional cargoes to Japan – on top of its term commitments – in 2013 should remain a bullish factor for European natural gas markets.

It is noteworthy that Qatar, with flatlining production, seems to be on something of a sales spree at present, with supply agreements either announced or reportedly under discussion with Egypt, Ukraine and Pakistan. Short-term contracts covered approximately 60 mt of volumes in 2011, double the amount in 2008. However, as Qatar locks up increasing volumes in these new longer-term contracts the volumes available to short-term contracts looks set to fall.

Iran

Iran contains the second largest gas reserves in the world, after Qatar, but political tensions and the sanctions imposed on Iran over its nuclear program have effectively stalled the development of these upstream assets. The government has continued with its fuel substitution policy, aimed at freeing up more crude for export through the substitution of natural gas. This, however, has resulted in gas shortages occurring in the winter months when residential and commercial demand is high. LNG export projects have been proposed in the past, but in the current political environment sanctions have meant a complete cessation of international financing and all projects are now indefinitely delayed. Pipeline exports to Turkey (and Armenia and Nakhchivan, though 90% of Iranian gas exports go to Turkey) appear to be continuing with Turkey now reportedly paying for the gas in gold; Citi's assumption is that these exports should decline as the Iranian oil and gas industry is starved by the sanctions.

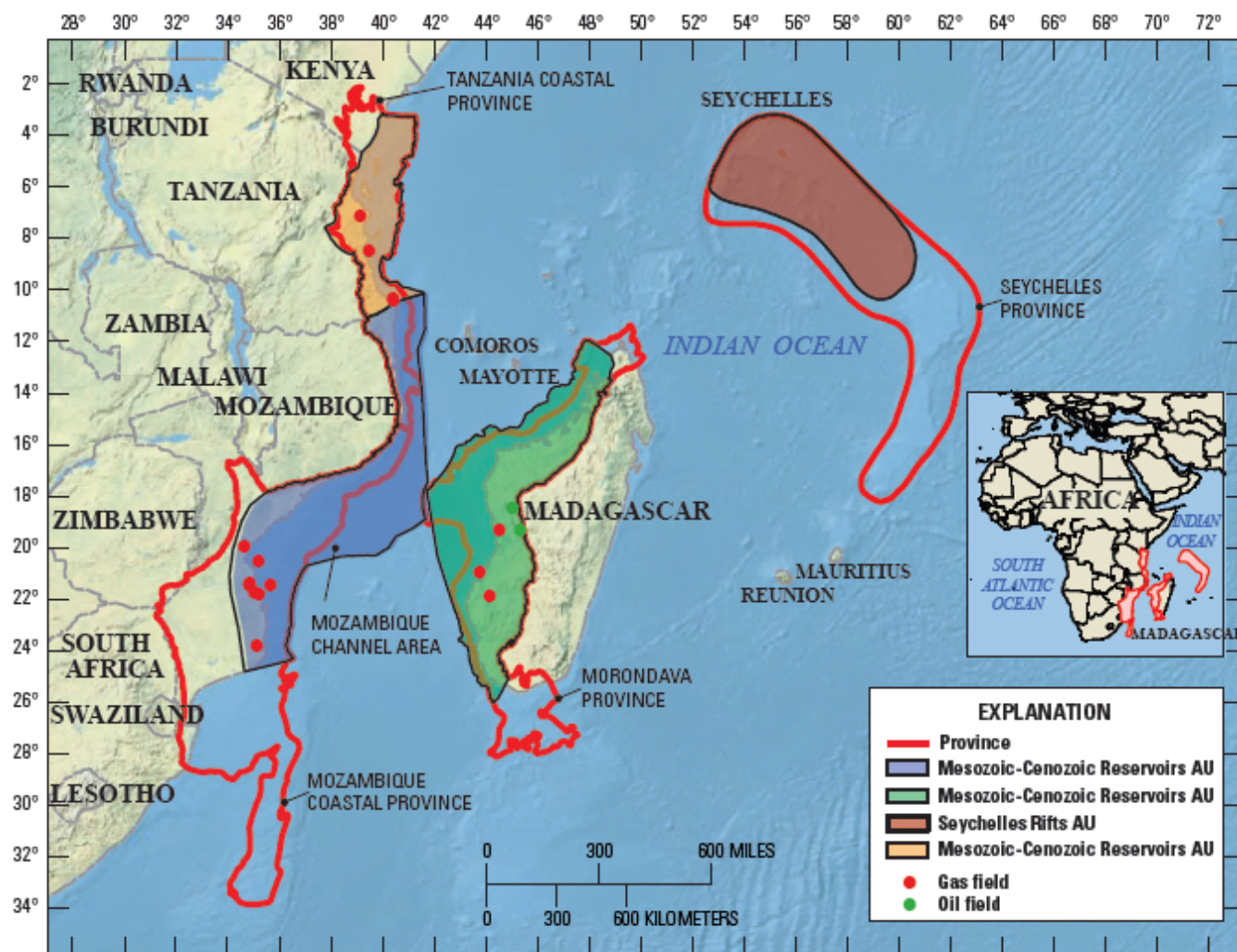
Furthermore, much Iranian gas is associated, so the curtailment of production in the face of sanctions on exports of crude may already be materially impacting Iranian gas production. Going forward, Citi's assumption is that these sanctions continue to restrict gas production, but it is worth noting that with all the attention the oil markets pay to Iran, any normalization of relations with Iran could be more bearish for natural gas in the long term, than for oil, given the massive reserves in the country.

East Africa

East Africa – particularly Mozambique and Tanzania – is a hotspot for gas exploration and discoveries, with vast reserves (that could see further upside) able to support significant LNG supply, albeit likely beginning towards the end of this decade. Not only is the resource large, but East Africa is also well positioned to supply Asian as well as European markets. However, as a frontier region, there are drags from technical as well as commercial challenges, which could delay development.

East Africa has been home to recent major gas discoveries, with around 100 Tcf discovered to date – Mozambique's Rovuma Basin was a major contribution to global discovered reserves in 2011. While smaller, Tanzania's reserves of 33 Tcf have seen continued revisions upwards as new discoveries continue to be made, and exploration exceed expectations. Kenya could contribute further volumes.

Figure 51. East Africa oil and gas resources



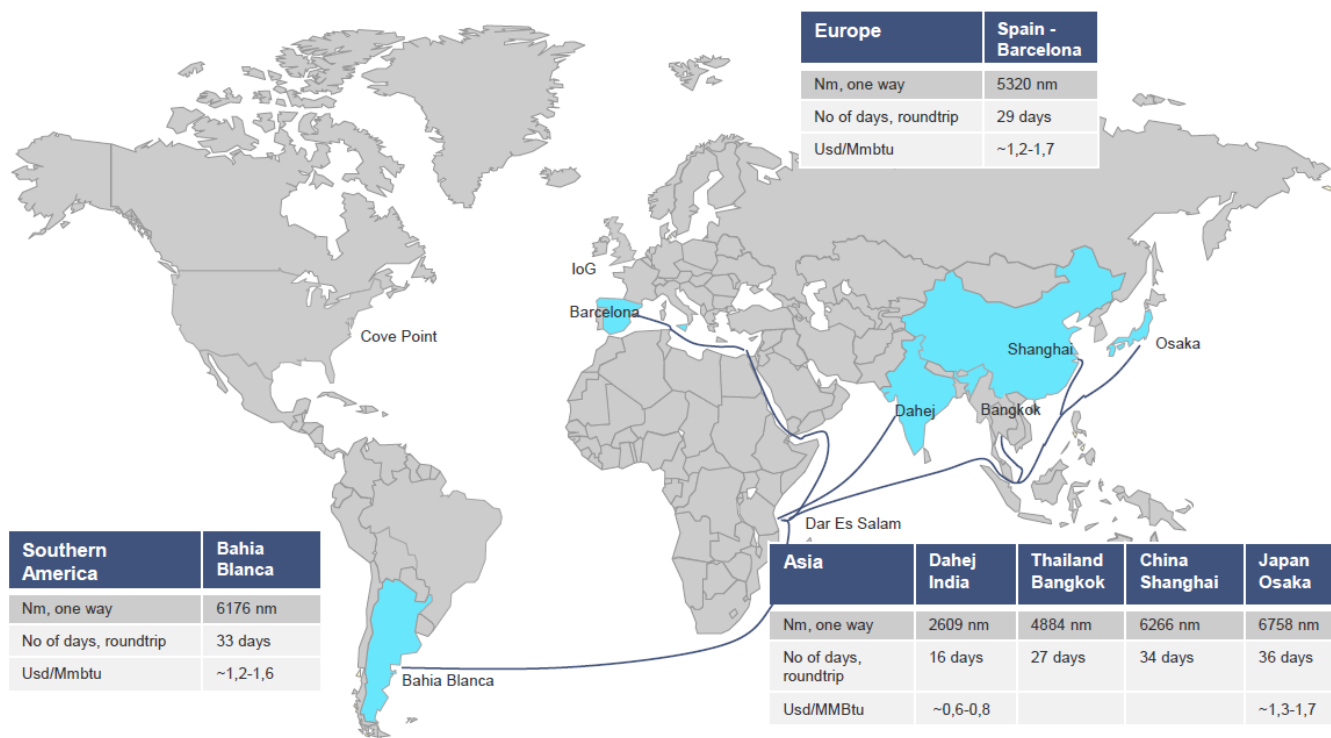
Source: USGS

The discovered reserves have major supply potential, with Mozambique's reserves potentially able to support 16 LNG trains. So far, some six LNG train projects have been proposed for Area 1, and another two for Area 4, but the resource potential allows for further expansion. Anadarko has started work on an initial two-train 10 mtpa plant, with final investment decision for late-2013. The timeline for LNG supply remains a long one; Wood Mackenzie assumes four trains from Mozambique and one from Tanzania towards the end of this decade, which would supply some 4.2-Bcf/d at its peak, but this could well undershoot actual development. With Citi's model seeing global gas supply growth of over 40-Bcf/d worldwide in a base case, East African supply upside could boost this further.

Given its geographic location, East Africa is in a prime position to supply fast-growing Asian markets, as well as diverting westwards to Europe as needed. Transit times range from 16 days to India to 36 days to Japan. Kogas's involvement in Mozambique should help marketing efforts to North Asia. Europe (Spain) can be reached in 29 days at \$1.2-1.7/mmbtu. But closer to home, South Africa could also be a potential market; while South Africa itself is abundant in shale gas resources, its moratorium on shale development limits its supply growth and present an

opportunity to East African suppliers. The breakeven costs for the Mozambique projects look to be in the \$8/mmbtu range. This could mean \$10/mmbtu in terms of a delivered North Asian LNG price, which would sit somewhere squarely in the middle of the global supply curve.

Figure 52. East Africa is in prime position to supply Pacific and Atlantic Basin LNG markets



Source: Statoil

Although the resources are significant, East Africa remains a remote, frontier region, and thus undeveloped infrastructure and hydrocarbons service sectors could hinder the timescale for development. There are also regional issues with piracy. Commercial issues – fiscal terms and financing – could also face challenges, with Tanzania recently declaring that it would review all its international contracts, spooking IOCs, though later retracting this. Mozambique, though, looks to have a more favorable investment environment.

Australia

Australia is in an LNG development boom and could be exporting over 12-Bcf/d by 2020, making it perhaps the largest supplier country in the world by that time. It has as many as seven LNG projects in construction simultaneously, adding over 60 mtpa of capacity, with 33 mtpa of capacity commissioned in 2011 alone. Australia thus adds significant volumes to global balances and is geographically positioned to benefit from growing Asian and Pacific Basin demand, as well as being regarded as a reliable long-term partner. But it faces significant competition from North American exports that should put downward pressure on Asian prices, while costs of Australian LNG are relatively high and rising as labor and service shortages are being faced at home. Cost overruns and delays have plagued developments and look to continue going forward, putting pressure on future investment decisions. For instance, Chevron's 15 mtpa Gorgon LNG project had a budget of \$37 billion when sanctioned in 2009, but actual costs could reach \$50-60 billion.

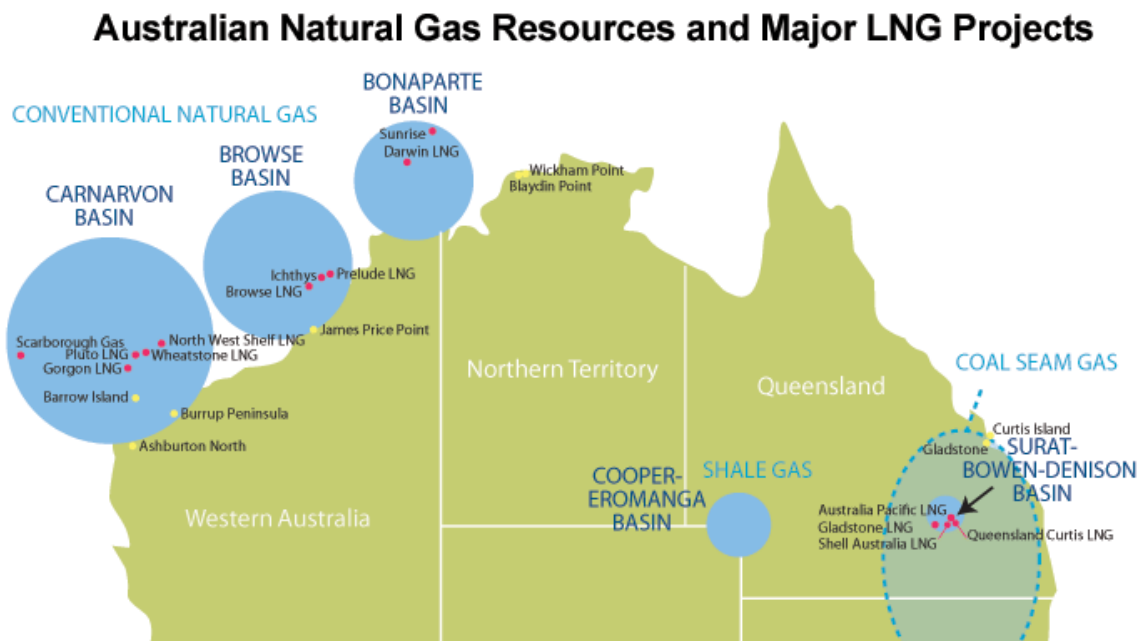
Its gas reserves are predominantly found offshore on the North West Shelf in the Carnarvon, in the Bass Strait of the southwestern Gippsland Basin off the coast of Victoria, as well as onshore Surat and Bowen basins in the northeast. Until the late-1980s, gas sales grew along with domestic demand, but 1989 onwards, Australia's exportable surplus grew. The North West Shelf Gas Project (NWSGP) led the way, with five trains brought on stream by October 2008, with a total nameplate capacity of 17 mtpa, located in the northwest. The Darwin LNG project followed the NWSGP in February 2006, supplied by gas fields in the joint development area with Timor Leste, located in the north. A third project, Pluto LNG, was commissioned this year, supplied by the Pluto and Xena fields in the Carnarvon Basin, and has 4.8 mtpa of capacity.

The Gorgon field secured FID in September 2009 and could see first LNG in 2014, with 2.5-Bcf/d of supply perhaps by 2017. BG's Queensland Curtis coal bed methane (CBM) to LNG project took FID in 2010, and could also see first LNG exports in 2014, ramping up to 1.2-Bcf/d by 2017.

2011 was a landmark year with four projects securing FID, including GLNG and Australia Pacific LNG Train 1, also CBM-to-LNG projects, as well as Wheatstone LNG, and the floating LNG (FLNG) Prelude project. Together, these add 33 mtpa of LNG capacity. 2012 saw Ichthys and Australia Pacific LNG Train 2 taking FID. Australia Pacific LNG, Gladstone LNG and Wheatstone LNG could start-up in 2016, ramping up to full capacity of a combined 3.4-Bcf/d by 2018-19. Prelude FLNG – the world's first floating LNG supply – could start up in 2017, ramping up to 0.6-Bcf/d by 2019. Ichthys could start in 2017, ramping up to 1.4-Bcf/d by 2020.

Later in the decade could see expansions to Gorgon, Pluto and Wheatstone, as well as the Browse LNG project, a proposed three-train 12 mtpa project at James Price Point on the northwestern coast, and the Shell-PetroChina JV Arrow LNG, another coal seam gas to LNG project on the eastern coast, with two potential phases, a first two-train 8 mtpa followed by a further two trains to add another 8 mtpa of capacity. These and other proposed projects may start only towards the end of the decade or later. FID for Browse and Arrow are planned for 2013, though Browse has already encountered delays, but did receive environmental approval in November and has two off-take commitments from Osaka Gas and CPC in Asia. There remain environmental interest groups opposed to LNG exports that could hinder development; locating LNG processing plants offshore on floating LNG facilities may help address concerns. Two more FLNG projects have been proposed, Sunrise and Bonaparte.

Figure 53. Australian natural gas resources and major LNG projects



Source: Reserve Bank of Australia

Australian LNG supply is thus a key contributor to loose balances by the end of this decade, but does face challenges, including competition from US exports, as well as relatively high development costs. Development spending has risen from \$31 billion in 2011 to \$47 billion this year, and could rise to \$49 billion in 2013, but part of this spending increase has been due to cost inflation, which ran at around 20% in 2012 as demand for construction, materials and labor overheated. Meanwhile the strengthening of the Australian dollar has also contributed to rising US dollar price tags. Breakeven prices for new Australian LNG projects stand at around \$10-11/mmbtu, or around \$70-80/bbl oil.

These costs are driven by fuel and materials and sheer geographical distance – on land, this is between onshore gas fields to coastal LNG processing facilities; offshore, this is using several hundred kilometer-long subsea lines that cost in the hundreds of millions of dollars.

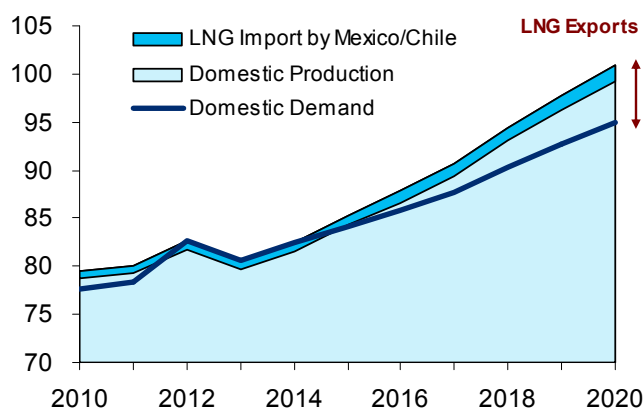
The role of unconventional gas for LNG is mainly in CBM-to-LNG, as detailed earlier. Since 2003, CBM production has grown to around 12% of Australian natural gas production, which stood at 4.4-Bcf/d in 2011. As a relatively new technology with no historical data as yet, the cost of CBM over the lifetime of production could be lower or higher than conventional gas. Upfront capital costs are lower, but many wells need to be drilled over time, shifting the balance of costs into the future. CBM is focused onshore in the eastern part of Australia and has faced opposition from farmers in the region. (As for shale gas, these are located in the more remote basins of Canning – in the northwest – and Cooper – in the eastern central areas – with their location affording them less contention from landowners.)

Labor costs are the other significant factor. The concurrent development of so many LNG projects at once has created huge demand for workers, driving up wages; at the peak demand of construction, some 1,500 to 2,000 personnel per day are needed per LNG train.

North America

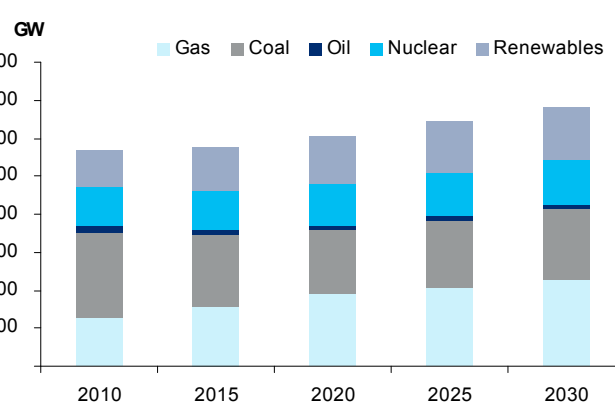
North American LNG exports should transform the global gas landscape. Low political risk and gas-indexation of prices appeal to importing countries looking for alternatives to oil-indexed gas, and leverage for negotiation with other current and future LNG exporters that would seek to link gas prices to oil prices. Rich gas from Western Canada and parts of the Gulf Coast, if developed, should draw further strong interest, too. Sabine Pass, the pioneering LNG liquefaction projection on the U.S. Gulf Coast, is already under construction and should enter into service in 2015. While other potential U.S. Gulf Coast projects are mostly brownfield developments, with lower costs and shorter construction time, Western Canadian export facilities are greenfield developments, which have a greater probability of delays or cost overruns.

Figure 54. OECD Americas projected supply-demand



Source: Citi Research

Figure 55. Electricity generation by fuel in OECD North America



Source: Citi Research

LNG exports from North America could total 10-Bcf/d or more by early 2020, with 5- to 8-Bcf/d coming from the Continental U.S., based on the current political appetite, and the rest split between Western Canada and Alaska. Only one terminal, Sabine Pass, in the Gulf Coast has been approved and is under construction. Another 2 to 3 terminals in continental U.S. could come online given the current political environment.

Market dynamics point to the U.S. being a global pricing hub in the years ahead for natural gas, petroleum products and even oil. As the U.S. is strategically placed as both an importer and exporter, the country can serve as the perfect weathervane of waterborne markets. At 5- to 8-Bcf/d, U.S. exports could supply 10 to 15% of the world LNG market by 2020.

Figure 56. US LNG exports cost stack

Japan		Henry Hub Prices (\$/MMBtu)				Europe		Henry Hub Prices (\$/MMBtu)			
	Unit cost	4.00	5.00	6.00			Unit cost	4.00	5.00	6.00	
Fee (Variable)	115%	4.60	5.75	6.90	Fee (Variable)	115%	4.60	5.75	6.90		
Fee (Fixed)	3.00	7.60	8.75	9.90	Fee (Fixed)	3.00	7.60	8.75	9.90		
Shipping (Panama)	1.70	9.30	10.45	11.60	Shipping	0.75	8.35	9.50	10.65		
Regas	0.40	9.70	10.85	12.00	Regas	0.40	8.75	9.90	11.05		
Oil-linked prices											
Oil Price (\$/bbl)	80.00	80.00	100.00	100.00							
Slope	0.15	0.15	0.13	0.13							
Oil-linked price (\$/MMBtu)	12.6	12.6	13.6	13.6							

Source: Cheinere, Citi Research

The delivered costs of U.S. gas to Asia could be between \$9.70 and \$12/MMBtu, and between \$8.75 and \$11 to Europe, based on a Henry Hub price of between \$4 and \$6. The chart below calculates each of the cost items using the Sabine Pass terminal as an example.

Figure 57. List of natural gas liquefaction facilities in operation, under construction, applied for approval or proposed in the U.S. and Canada

Project	Companies	Location	Capacity mtpa	Bcf/d	Year	Status
Canada						
Kitimat	Apache/EOG/EnCana	Kitimat, BC	10.0	1.3	2017	Approved
BC LNG	LNG Partners/Haisla	Kitimat, BC	1.8	0.2	2014	Applied
Kitimat Floating LNG		Kitimat, BC	0.6	0.1		Proposed
Kitimat LNG Exports	Kogas/Mitsubishi/CNPC/Shell	Kitimat, BC	13.1	1.7	2019	Proposed
Progress/Petronas	Petronas/Progress Energy	BC	7.4	1.0	2018	Proposed
Prince Rupert	BG					Proposed
US						
Kenai LNG	ConocoPhillips	Kenai, AK	1.5	0.2	1969	Operating
Sabine Pass Export	Cheniere	Cameron, LA	16.9	2.2	2016	Approved
Cameron LNG Export	Sempra	Hackberry, LA	13.5	1.7	2017	Applied
Carib Energy	Carib Energy (USA) LLC		0.2	0.03		Applied
CE FLNG	CE FLNG, LLC	Plaquemine, LA	8.2	1.1		Applied
Corpus Christi Export	Cheniere	Corpus Christi, TX	13.5	2.1		Applied
Cove Point Export	Dominion	Lusby, MD	5.0	1.0	2017	Applied
Elba Island Export	Southern LNG (El Paso)	Savannah, GA	3.8	0.5		Applied
Freeport LNG Export	Freeport/Macquarie	Freeport, TX	10.8	1.4	2016	Applied
Golden Pass	Golden Pass Products LLC	Port Arthur, TX	20.0	2.6		Applied
Gulf Coast LNG Export	Gulf Coast LNG	Brownsville, TX	21.5	2.8		Applied
Gulf LNG	Gulf Coast LNG Export, LLC	Pascagoula, MS	11.5	1.5		Applied
Jordan Cove	Jordan Cove Energy Project, L.P.	Coos Bay, OR	15.4	2.0		Applied
Lavaca Bay LNG (Floating)	Exelerate	Port Lavaca, TX	3.0	1.4	2017	Applied
Lefthand Bay	Shell	AK				Proposed
Main Pass	Main Pass Energy Hub, LLC	LA	24.8	3.2		Applied
Oregon LNG	LNG Development Company, LLC		9.6	1.3		Applied
Pangea LNG	Pangea LNG (North America) Holdings, LLC		8.4	1.1		Applied
SB Power LNG export	SB Power Solutions Inc.		0.5	0.1		Applied
Trunkline Lake Charles Export	Southern Union Gas	Lake Charles, LA	15.4	2.0	2018	Applied
Waller LNG	Waller LNG Services, LLC	Cameron, LA	1.2	0.2		Applied
North Slope Gas	Alaska Gasline Port Authority	Valdez, AK	20	2.6	2020-23	Proposed
Total			270.3	35.1		

Source: Citi Research

The prevailing doubt about the feasibility and sustainability of North American supply are likely overblown.

An export-supportive U.S. Energy Department report on LNG Exports⁴

On Dec. 5, 2012, the U.S. Department of Energy just released its second report assessing the economic impact of LNG exports. The study, feared by some that would be negative on exports by stressing the damage caused by higher prices to consumers and energy intensity industries, instead extolled on the economic benefits of exports. This could pave the way to more and faster LNG exports.

The long-awaited US Department of Energy (DOE) study demonstrates that a market approach allowing unrestricted natural gas exports provides benefits far in excess of costs. Key findings appear to strongly support exports, where the US would “experience net economic benefits from increased LNG exports.” Citi’s own dynamic model shows even more benefits, as an increase in U.S. exports could

⁴ http://fossil.energy.gov/programs/gasregulation/reports/nera_lng_report.pdf

induce an increase in Canadian imports, which would help cap U.S. prices. Canada, even without exports from the West Coast, can see tangible boost in exports to the U.S. DOE's respected consultant NERA seems to have not factored in enough of the ripple effects.

The DOE study, conducted by NERA – a very well-respected economic consulting firm – highlights how big a player U.S. can be. One of the scenarios portrays rapid growth to 12-Bcf/d of LNG exports, which would put the U.S. in major exporting leagues rivaling Russian pipe exports, Qatar's current 10-Bcf/d of LNG exports and Australia's expected LNG exports of 11.5-Bcf/d, counting only projects that are operational or under construction. In the high/rapid case considered by the study, the U.S. could surpass both Qatar and Australia with 12-Bcf/d of exports.

The study considered a number of scenarios based on different ramp-up rates⁵ of LNG exports and different shale gas recovery rates. The recovery rate of gas, or Estimated Ultimate Recovery (EUR), is based on assumptions used in the 2011 Annual Energy Outlook prepared by the EIA,⁶ using data from 2010 and before. The high EUR case assumes 50% more recovery than the ones used in the base case. Note that recovery rates have had vast improvements in the last few years due to better identification of drilling "sweet spots," technological improvements and learning-by-doing. The high EUR case can reasonably be taken as a base case going forward.

Figure 58. Continental U.S. export capacity limits studied by NERA

Scenarios Bcf/d	2015	2020	2025	2030	2035
Low/Slowest	0.5	3.0	5.5	6.0	6.0
Low/Slow	1.0	6.0	6.0	6.0	6.0
Low/Rapid	3.0	6.0	6.0	6.0	6.0
High/Slow	1.0	6.0	11.0	12.0	12.0
High/Rapid	3.0	12.0	12.0	12.0	12.0
No Constraint					

Source: EIA, Citi Research

Further economic benefits can be gained by using a higher, more realistic EUR and assuming that U.S. firms can take on a more active role. In some high EUR cases, NERA found that despite more than 12-Bcf/d of LNG exports, "there were net economic benefits from allowing unlimited exports in all cases." Results from the study also indicate that the economic benefits increase as the amount of exports rises, even assuming the "highest prices estimated by the EIA for these hypothetical cases" because of the rise in export revenues. The U.S. stands to gain more economic benefits if local firms take on more of a "merchant" role, rather than just processing the gas, as profits would be retained in the U.S.

The impact on the employment and output of energy intensive industries was estimated to be less than 1% in any year in all export cases. This could assuage some concerns about the potential downside to the economy and possibly weaken economic arguments against gas exports.

⁵ Different export quota trajectories were assumed, either that exports increase by 1-Bcf/d per year ("Slow") or 3-Bcf/d per year ("Rapid"), reaching a cap of 6-Bcf/d ("Low") or 12-Bcf/d ("High"). Additional trajectories include a zero export option and a slower ramp-up rate of 0.5-Bcf/d per year until 6-Bcf/d of exports are achieved.

⁶ Energy Information Administration is the independent statistical arm of the U.S. Department of Energy.

Of greater significance is the potential for an eventual study on oil exports from the U.S. Given the free-market logic from the NERA study, oil exports could also be viewed as beneficial to the U.S. economy.

U.S. LNG Exports Impact on Domestic Prices

Concerns that natural gas prices could surge should be mitigated by the pricing mechanism in the export market: higher domestic U.S. prices lead to higher delivered costs of gas in Asia. Unless importers can tolerate these high prices, the demand for this high-priced U.S. gas should fall as U.S. gas becomes uncompetitive in Asia. In fact, the NERA study showed that in no case does the U.S. wellhead price rise by more than \$1.09/Mcf in 2035 vis-à-vis the base case.

Figure 59. Changes in U.S. natural gas prices vs. the baseline of zero exports (2010\$) using results from DOE's second export assessment report⁷

Cases	EUR	Supply Shock	Demand Shock	Maximum Export (Bcf/d)	Pace of increase (Bcf/d/year)	2015	2020	2025	2030	2035
Projected Wellhead Prices (2010\$/Mcf)						\$3.83	\$4.28	\$5.10	\$5.48	\$6.36
1	Reference	Y	Y	6	3	\$0.33	\$0.65	\$0.52	\$0.47	\$0.41
2	Reference	Y	Y	6	1	\$0.10	\$0.65	\$0.52	\$0.47	\$0.41
3	Reference	Y	Y	12	3	\$0.33	\$0.92	\$1.02	\$1.03	\$0.89
4	Reference	Y	Y	12	1	\$0.10	\$0.65	\$1.02	\$1.03	\$0.89
5	Reference	N	Y	6	3	\$0.31	\$0.27	\$0.33	\$0.24	\$0.25
6	Reference	N	Y	6	1	\$0.10	\$0.27	\$0.33	\$0.24	\$0.25
7	Reference	N	Y	6	0.5	\$0.05	\$0.27	\$0.33	\$0.24	\$0.25
8	High	Y	Y	12	3	\$0.27	\$1.11	\$0.84	\$0.68	\$0.67
9	High	Y	Y	12	1	\$0.08	\$0.47	\$0.75	\$0.68	\$0.67
10	High	Y	Y	6	3	\$0.27	\$0.47	\$0.37	\$0.31	\$0.31
11	High	Y	Y	6	1	\$0.08	\$0.47	\$0.37	\$0.31	\$0.31
12	High	Y	Y	6	0.5	\$0.04	\$0.22	\$0.34	\$0.31	\$0.31
13	High	Y	Y	6	0.5	\$0.00	\$0.37	\$0.22	\$0.00	\$0.04

Source: DOE, Citi Research

As the DOE study also illustrates, the price impacts are mostly muted if a gradual ramp-up takes place, particularly if only a maximum of 6-Bcf/d of gas is exported.

The talk that domestic U.S. gas prices could surge when LNG cargoes are exported from the continental U.S. unconstrained may have overlooked a couple of factors: Canadian gas exports to the U.S. effectively re-exported globally, and a market pricing mechanism that shuts down exports when high Henry Hub prices make the delivered cost of LNG uncompetitive in Asia and elsewhere globally.

First, U.S. gas supply should not be thought of as being restricted to U.S. production, but should also include Canadian production. U.S. LNG exports could, ironically, be supported by increased gas imports from Canada through a displacement of Gulf Coast gas, as gas markets in the U.S. and Canada are in fact the same one system. With the difficulty in expanding the route for West Coast exports of LNG, Canadian gas can still follow its traditional export routes of sending gas to the U.S. via existing pipe infrastructure. Prices above the lows in the \$2 to

⁷ A supply shock assumes that an LNG exporting region fails to increase exports above current levels. A demand shock involves the closing of Japanese nuclear. A "supply and demand" shock together involves the combination of the above, as well as retirements of Korean nuclear units. The recovery rate of gas, or Estimated Ultimate Recovery (EUR), is based on assumptions used in the 2011 Annual Energy Outlook prepared by the EIA, using data from 2010 and before. The high EUR case assumes 50% more recovery than the ones used in the base case. Note that recovery rates have had vast improvements in the last few years due to better identifications of drilling "sweet spots," technological improvements and learning-by-doing. It would appear that the high EUR case should be the base case going forward.

\$3 range should make gas drilling economic again in Alberta. Increases in Canadian gas production and exports to the U.S. are highly feasible. Imports from Canada to the U.S. have long been supporting U.S. gas exports to Mexico. The U.S. has a history of importing a much higher amount of Canadian gas and the pipeline infrastructure can support an increase. Canadian gas could still flow to the U.S. Midwest. Along with Marcellus gas in the Northeast part of the U.S., this Canadian gas should displace Gulf Coast gas that traditionally moves north to serve the Midwest and Northeast markets. Gas staying in the Gulf Coast would simply serve gas demand needs in the South, Southeast and LNG exports. Stranded gas in Canada without an outlet should start producing as well.

Second, a rise in gas price could effectively shut off exports, as U.S. Gulf Coast gas becomes uncompetitive overseas. For example, if gas prices in the U.S. were to rise to \$6/MMBtu, then the cost of gas delivered to Asia should be \$12/MMBtu, within the current range of LNG prices in Asia. However, if Henry Hub gas prices were to rise to \$7 or above, then the delivered cost of U.S. gas in Asia should rise above \$13/MMBtu, pricing out U.S. gas exports. Hence, if the longer term price will indeed be in the \$11 to \$14/MMBtu range, and that lower oil prices effectively lower the oil-indexed price of gas in Asia, then delivered US LNG prices above this range would sharply reduce the appeal and demand for US LNG. As exports fall, gas demand eases in the U.S., setting a soft cap on U.S. gas prices.

Domestic U.S. demand could certainly grow, but the production growth could be even more prolific. US production can reach 84-Bcf/d by 2020 from the 65-Bcf/d even at the current gas rig count of under 400 – a multi-year low and less than half of the average rig count in 2011 – because of improvements in technology, drill time and production rates, as well as associated gas production coming from increased the oil and liquids production. In the short term, the possible production decline in 2013 and 2014 could be cushioned by the coming online of drilled-but-not producing wells. A modest increase in gas rig count, off the multi-year low of just under 400, could boost production to accommodate the increase in gas demand. Low production costs should remain in place, limiting the price increase that hurts domestic industries.

Associated gas production growth from oil and liquids-rich plays could reach 2.0-Bcf/d in 2013 due to strong liquids production growth. This pace should continue through to the end of the decade as long as oil and liquids production keeps up. Citi is forecasting that oil production could climb by 0.5-mb/d and NGLs higher by 0.2- to 0.3-mb/d YoY in 2013. The growth should mostly happen in PADDs 3 and 2, which includes North Dakota.

Current status on LNG exports

Citi expects a decent pace of licensing, with an export market potential of 5 to 8-Bcf/d. At least 1-Bcf/d per year, if not 3-Bcf/d, could be licensed in the next three years. The licensed volume will likely exceed actual volumetric growth, as market forces should cap the amount of exports based on global demand and prices. Excelerate's floating LNG terminal could add at least 0.7-Bcf/d starting in 2017.

Political forces could hinder the process but this is not probable, as the House of Representatives is controlled by the Republicans, with their general support for trade and oil-gas drilling, and a Presidential veto looks unlikely, since gas is not in short supply and is not strategic. Political opposition in the House and Senate is just another obstacle to Pacific-based exports other than Alaska.

US LNG exports took a step forward when the Sabine Pass liquefaction terminal announced its final investment decision (FID) on Aug 1, 2012. It may begin operation much sooner and directly export Henry Hub prices overseas. The terminal is the first to have permits to export LNG out of the Continental U.S. to non-Free Trade Agreement (FTA) countries. It announced that the first unit of its project, set to be completed by late 2015 to early 2016, is 6 months ahead of schedule and the second unit 11 months ahead of schedule. As such, around 2-Bcf/d of gas could be processed by the terminal for exports in 2016.

Japanese companies have been very active in other terminals: Sumitomo/Tokyo Gas in Apr'12 signed with Dominion's Cove Point terminal for 2.3-mtpa of capacity; Mitsubishi, Mitsui and GdF Suez in May'12 signed with Semptra's Cameron terminal for 12.0-mtpa of capacity; and Chubu Electric and Osaka Gas in Aug'12 signed agreements with Freeport for 4.4-mtpa of capacity. The heavy involvement by Japanese players could be a reflection of several factors: the country's need for LNG and diversity of sources, the uncertainty over which terminals could be built, and the terminals' interest in obtaining low-cost financing provided by the official or semi-official sector of Japan. However, since Gulf Coast gas is lean, it only appeals to a few Japanese regas terminals.

A number of liquefaction projects have received approvals to export gas to FTA countries, which only include a handful of nations, such as Chile, Israel, South Korea and Singapore⁸, but not Japan.⁹ But terminals are looking to receive government approvals to export to non-FTA countries. Theoretically, gas can be exported to FTA countries and re-exported elsewhere, or that US LNG could displace existing cargoes heading to FTA countries and be diverted elsewhere. Nevertheless, destination clauses could limit where these original cargoes could go and political pressure in the U.S. could present obstacles to such practices.

Currently, project approvals have been on hold pending an Energy Department assessment on the economic impact of U.S. gas exports, set to be released before the end of 2012, with the Presidential election over. The report's findings and recommendations could signal where the U.S. government is leaning and how much exports could be possible.

Most proposed terminals are located on the Gulf Coast but it appears that, outside of the Sabine Pass terminal, only one or two could be approved, if the 5- to 6-Bcf/d of export limit were to hold. Freeport was the earliest in the approval queue that has not yet received a go-ahead from the government. If approved, it could reach Final Investment Decision by late 2013 and start exporting by 2016 or 2017. Cameron, Golden Pass, which is a joint venture between Qatar and Exxon, or others, could also be joining Sabine Pass in exporting gas. Golden Pass, sitting across from the Sabine Pass terminal, is an intriguing prospect. If approved, Golden Pass could have a capacity of 2.2-Bcf/d at an estimated cost of \$10 billion. Qatar, as the majority equity partner in the project, happens to seek oil-indexed pricing for long term contracts of LNG produced in Qatar. Rather than being absent at the seeming reality of US LNG exports, Qatari's entry could instead improve its market power by letting it control one of the terminals, instead of other parties. It can divert its 2-Bcf/d of gas to wherever it finds most profitable to its portfolio or as a swing supplier

⁸ FTA approvals are done within a matter of weeks, as the U.S. Natural Gas Act states that exporting gas to FTA countries is in the public's interest and the Energy Department should be done without modifications or delay.

⁹ If Japan, currently an observer but not member, joins the Trans-Pacific Partnership, the country could effectively obtain FTA status for energy exports. But also opening up the agricultural, autos and insurance markets to foreign competition could be the sticking point.

with two global hubs: one at its home base in the Middle East, serving Asia and Europe, and another in North America serving Asia, Europe and South America.

Terminals on the East Coast, mainly Cove Point if it is completed, could take advantage of its proximity to the Marcellus, one of the largest gas fields globally, and the shorter distance to Europe than exporting from the Gulf of Mexico. A liquefaction terminal on the East Coast would have a more direct impact on forming a natural gas highway between Europe and North America. Previously, the Trans-Atlantic LNG bridge was provided by LNG cargoes coming from Africa, the Caribbean or the Middle East, where the East Coast of the US or Northwest Europe would compete for spot cargoes depending on their respective demand needs. However, with the advent of the shale gas boom, the U.S could have the ability to ship gas to Europe from the East Coast, constituting a link between the two regions

Terminals on the West Coast are very unlikely to be approved due primarily to environmental and other political opposition. The opposition could go beyond the terminals themselves, but the pipelines that bring gas all the way to the coast.

US Gas Demand

While the supply and inventory overhang has capped gas production growth, demand growth is accelerating on the prospect of relatively low gas prices for years to come. These demand-side transformations should take place in the following sectors:

Power generation: Load growth, however small, would be captured by gas-fired generation, potentially adding 0.5 to 1.0-Bcf/d of demand by the middle of the decade, to total an increase of 5-Bcf/d by 2015. Permanent coal-to-gas substitution due to coal retirements, assuming 50-GW of capacity that had been running at about 40% utilization, could contribute 4-Bcf/d of additional gas burn. Why retire? Relatively low gas prices threaten the economics of coal power plants, just as coal prices remain elevated, in addition to a number of emission rules raising the capital and operating costs of coal plants

Industrial renaissance: The re-industrialization of America is underway based on dramatically lower cost feedstock than is available anywhere in the world, with the possible exception of Qatar. This benefits sectors ranging from petrochemicals to steel. Besides the increased use of gas as a feedstock, fuel substitutions, from both oil and coal to gas, could add nearly 2-Bcf/d of demand across sectors by 2015 and 3-Bcf/d between 2012 and 2017. This could include retrofits or conversions adding to baseload demand.

Residential and Commercial: Switching from heating oil to gas for heating could quickly recoup benefits, while the reduction in vacancy rates should return empty units that had been using no or very little demand to an average level of demand. The ResComm sector could add 0.6-Bcf/d of demand by 2015.

Transportation: The wide price spreads between diesel and natural gas, as well as company-level push in the adoption of gas by logistics companies (eg. UPS, FedEx, etc) could finally make CNG and LNG work in heavy duty trucking. The pipeline and refueling infrastructure developed could also kick-start fuel conversion in medium-duty trucking and other light vehicles. The transportation sector could add 1-Bcf/d of demand by 2016.

Alaskan production growth could reach 4-Bcf/d or more by early 2020, driven by LNG export demand. Previous proposals of moving the stranded gas in the North Slope in Alaska via the Alaska gas pipeline down to Canada and the Lower 48 states would have unlocked the 4-Bcf/d of production potential, but the high cost of building the pipeline, sizable tariffs involved in transporting the gas and the subsequent boom in shale gas production made these proposals uneconomic. Instead, as gas prices in Asia should remain elevated despite new LNG supplies coming online in Australia and elsewhere later, this new source of Alaskan LNG would be economic, even though new gas pipelines would have to be built from the North Slope to southern Alaska.

The uncertainty lies partly on the timeline to get projects off the ground. The consortium led by ExxonMobil, Conoco, BP and TransCanada estimated in October that a liquefaction project could cost between \$45-billion to \$65-billion and take around 8 to 10 years or more to complete, from permitting and obtaining financing to front end engineering design and construction. It involves building a 1,300-km (800-mile) pipeline with capacity of 3 to 3.5-Bcf/d from the North Slope to the southern Alaska. Completion could come in phases, instead of having multiple trains all at once. The liquefaction terminal could consist of three trains for a total capacity of 1.9 to 2.3-Bcf/d.

Canadian export

LNG exports from the West Coast of British Columbia, Canada, could quickly emerge as another source of gas supply to Asia. With stranded gas up in British Columbia and Alberta, the interest to export gas to Asia is driven by the steep decline in exports to the U.S. but high Asian gas prices.

Two areas are being discussed: Kitimat has the most advanced development, with Kitimat LNG, BC LNG and LNG Canada all planning to build terminals. Prince Rupert to the north of Kitimat is also being discussed, with BG and Petronas/Progress being involved. Thus far, only Kitimat LNG and BC LNG have received export licenses from the National Energy Board (NEB) – the regulatory body in Canada. Although Kitimat does have access to the existing Pacific Northern system, its capacity is only 0.1-Bcf/d, insufficient for the amount required to feed proposed liquefaction terminals. Hence, new pipelines being proposed include the Pacific Trail pipe – the only one permitted – that connects to Kitimat LNG, as well as TransCanada's Coastal GasLink by TransCanada, among others.

Target markets include Japan, South Korea, China and even Southeast Asia. Although the Kitimat LNG project has the earliest start of all major projects, LNG Canada – a consortium of producers and consumers – may have the leg up. In contrast, other than Petronas/Progress, others seem to be much further behind. Kitimat LNG's equity partner includes Apache, EOG and EnCana – all North American producers that appear to be looking for oil-indexed gas prices. However, with a number of liquefaction projects coming online towards the end of the decade, importing countries have shown little interest in oil-indexed gas. If Exxon's interest in Kitimat is indeed real and becomes an equity partner, the company has shown that it can accept below oil-indexation price. The 20-year deal between Taiwan's CPC and the Exxon-led Papua New Guinea was priced under the prevailing oil-indexation. Exxon's interest could stem from the Horn River gas that it owns but might be too expensive for the current U.S. and Canadian market. LNG Canada's equity partner includes Shell, PetroChina, Mitsubishi and KOGAS – all major producers and importers. This structure puts the project ahead of the pack.

While LNG suppliers want to secure oil-indexed pricing, perhaps at just under the highest priced supplier, as our LNG supply-demand indicates, excess LNG liquefaction may not be needed. However, these projects could still be rather profitable by capturing two sets of rents even if prices are indexed to some North American gas price: gas processing and logistics, as well as the price spread between hub prices and the breakeven cost of production. First, in gas processing and logistics, firms could charge a premium for processing the gas and possibly delivering the gas LNG, given the limited availability. Second, a vertically integrated player could capture the price spread between the breakeven cost of a play a nearby hub price. If a benchmark price, such as Henry Hub, were to use, then the LNG supplier could charge a premium on the basis, or price differential, between Henry Hub and the price hub nearest to the production area supplying the LNG terminal.

Canada has been a major supplier of gas and oil to the U.S. But the shale gas boom in the U.S. has cut its imports of Canadian gas sharply, from 8.2-Bcf/d in 2008 to under 5-Bcf/d as of late 2012. Our projection suggests that Canadian gas exports to the U.S. could stay low through 2014, which should drive production lower. Instead, high gas prices in Asia are attracting developments of liquefaction facilities on the West Coast of British Columbia, a province of Canada.

However, Canadian production could rise again on three major factors: LNG exports from Canada, oil sands development and rising demand from the U.S. for its domestic consumption and LNG exports. Note that the gas market in Canada and the U.S. is essentially one system, with a very well-developed pipeline network across the continent.

As with oil exports on the West Coast of Canada, direct gas exports from British Columbia to Asia does encounter some obstacles: the high cost of building pipelines to the coast and the expense on constructing liquefaction terminals, besides the need to resolve right-of-way issues involved in putting up these new infrastructure. Nevertheless, the export of Canadian gas to the U.S. can increase. By supplying the northern tier of the continental U.S., gas that traditionally comes from the Gulf Coast to the Midwest and Northeast of the U.S. could instead be displaced and supply demand in the south and supply LNG exports. This system would then be akin to the one being discussed on the oil side, where Canadian crude oil would be shipped to the Gulf Coast.

Rather than buying gas from nearby gas market hubs, such as AECO in Alberta or other pricing points priced off AECO, a number of LNG players are also active in gas exploration and/or production in Western Canada to secure gas resources. Gas plays in Western Canada provide vast resources for exports. They include Duvernay in Alberta, Montney that straddles Alberta and British Columbia, as well as Horn River, Liard Basin and Cordova Embayment in British Columbia.

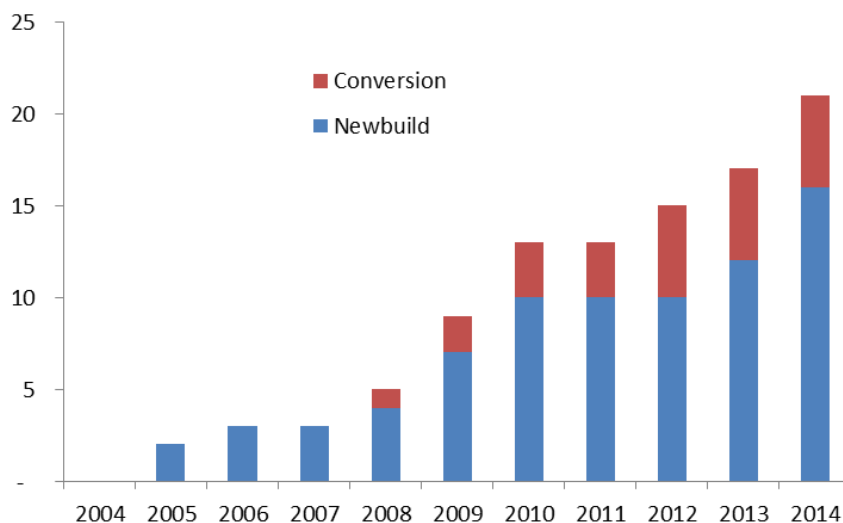
- The 120-Tcf Montney is currently producing about 1.5-Bcf/d, but the liquids-rich area could receive greater attention in later years given the premium liquids have over dry gas. As the play is located just underneath existing pipeline infrastructure, the cost of development is largely lower than other plays in this list.
- The 90-Tcf Horn River in northeast British Columbia is currently producing about 0.5-Bcf/d, but the play is heavy in dry gas. Despite its resource base, low gas prices, its remoteness and the need for additional processing have slowed its development.

- Next to Horn River is the Liard Basin, which is very early in its development. Its dry gas resource is thought to be sizeable and possibly with some liquids potential. Apache's well appears to show very strong results.
- Exploration activities suggest that Duvernay could be liquids-rich. It is also close to the existing pipeline infrastructure in Alberta but it is still very early in its development. High well costs are hampering its development currently.
- Cordova Embayment to the east of the Horn River play, very early in the exploration stage, could have large dry gas potential as well, but the aforementioned plays have gained more attention.

Floating liquefaction, regasification and LNG tankers

Technology is doing its part to keep short and medium term LNG markets tight, by giving demand a boost without having a similar impact on supplies so far. Floating regas vessels are significantly quicker and cheaper to implement than their traditional land based equivalents. On the supply side, floating liquefaction is coming, bringing some improvements in terms of flexibility. But a 0.5 Bcf/d FLNG vessel should, according to Woods Mackenzie, cost about \$6bn, while on the demand side, a similarly sized floating regas vessel should cost all of \$300mn. FRSUs are already active and more are coming to market as the chart below indicates. In 2011 Shell committed to a FLNG vessel to operate off Western Australia, starting in 2017. But in 2012 Petronas took FID on a less complex FLNG project now scheduled to start in 2015.

Figure 60. Number of FSRUs



Source: Woodmac, Citi Research

FSRU

FSRU, or Floating Storage and Regasification Units, operates offshore to regasify LNG into gas for use onshore. Due to its mobile nature, FSRUs are suitable for locations where demand for LNG is highly seasonal or variable. It also fits the needs of places that want to get gas sooner, whether it is due to the protracted nature of obtaining permits or the extended construction period for an onshore facility. In addition, onshore environmental concerns or other land use issues preventing the construction of a regas facility could find FSRU a better choice than not having the gas supply.

A number of nations are already using floating regasification terminals to manage their gas demand needs, among them Argentina, Brazil, Kuwait and Dubai. Indonesia, Israel, Lithuania and others could be adopting FSRUs in the next couple of years. FSRU is deployed in Brazil due to the large swing in the country's hydro generation. Israel is trying to bridge its gas need until its offshore fields are developed amid a supply disruption of pipe gas from Egypt. Selected Middle East countries have been using FSRUs to supply their summer gas demand requirement for power generation, but the strong growth in electricity consumption and the

resulting gas demand is making FSRUs a more permanent fixture, perhaps until those locations develop their own gas fields. Gas demand may also be rising at a much faster-than-expected rate that new regasification builds may not be ready in time to meet domestic needs.

There could also be economic reasons for switching to gas. Island nations that had been using diesel or fuel oil for generation may be looking to switch or retrofit their power plants to burn gas instead of oil. Coupled with the seasonal nature of some their demand, a floating facility becomes a preferred choice. Some oil producing countries, especially in the Middle East, that have been using petroleum for power generation are also looking to replace oil as a fuel to gas.

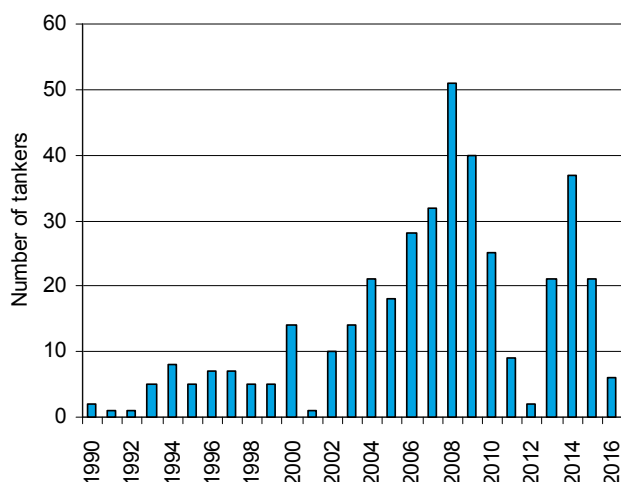
FLNG

Floating LNG vessels can help monetize gas assets that are too small or remote to justify their own conventional liquefaction facility. Apart from Australia and Malaysia, FLNGs are being considered for Papua New Guinea, Indonesia, and Israel amongst others. The technology does have the potential to revolutionize LNG supplies just as FPSOs impacted the offshore oil industry, but for now the technology remains untested and so far does not appear to offer much by way of cost savings – the potentially lower capex is countered by higher operating costs.

Tanker – after a period of tightness, new builds entering the market should reduce shipping cost and flexibility

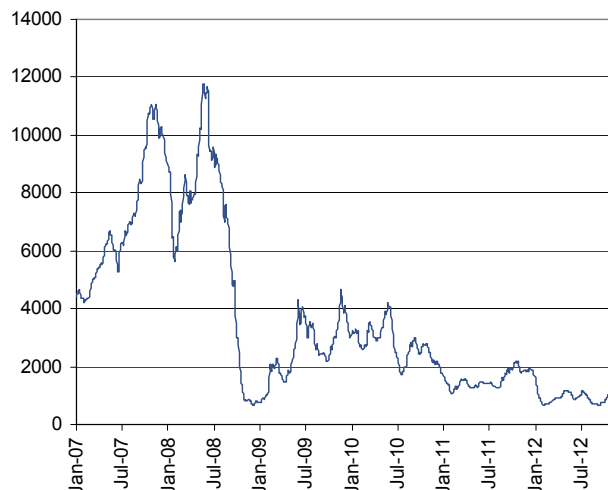
As dayrates surged to over \$150,000/day, a number of new ships were ordered in 1H'12. Low freight rates in other parts of the marine transport sector also allows shipbuilders capable of building LNG tankers or floating LNG facilities to participate in this building boom.

Figure 61. Expected number of tanker deliveries



Source: Woodmac, Citi Research

Figure 62. Baltic Dry Index



Source: Bloomberg, Citi Research

But the freight business is prone to boom-bust cycles. Dry bulk freight saw a massive number of new build orders in the couple of years leading up to the Great Recession in 2008. As a result of the dry bulk and metals shipping boom, many new ships were ordered before the crisis but went into service after, just as global trade slowed sharply and slower economic growth reduced the need for metals and bulks. The Baltic Dry Index, an industry index of freight rates for dry bulks, fell sharply from near 12,000 in mid-2008 to around 1,000 in late 2012.

Hence, although LNG demand is expected to rise, its growth may not be as strong to keep dayrates up. Lower dayrates should lead to lower per unit transport costs, which means that the cost of long haul shipping, such as the U.S., to Asia would be lower, thereby making U.S. or other long haul gas more competitive. That some shipyards are more willing to take on LNG tanker projects could mean more supply of ships starting in 2014.

International Shale

Shale gas has already transformed the natural gas market in the US and is beginning to have an impact in Canada. The prospects of the shale gas revolution spreading from the US to other countries is a material risk to our forecast for LNG demand and hence prices. Citi expects many headlines but little by way of actual production outside of some small experimental projects for the next several years. By late decade some small volumes look likely to be flowing from China, Argentina and there are several other candidates, but for now Citi is cautious on the prospects as no other country has the same combination of factors – geology, water abundance, mineral rights, oil service industries, a proliferation of small independent upstream operators, and a unique capital markets structure that is used to financing exploration risk – that came together for the US.

The spectacular success of US shale gas and oil production and its dramatic impact on the country's industry and energy security has sharpened focus on the possibilities for shale internationally. As an extremely common source rock for hydrocarbons, potentially large resources exist worldwide, with significant volumes reported in EIA's world shale gas assessment in China, Australia and India in Asia; across Latin America in Argentina, Mexico, Brazil, Chile; South Africa and north African countries Libya and Algeria; and even Europe, in Poland, France and Norway. Outside of the EIA assessment, there could be significant volumes in the Middle East, as well as in Russia's Bazhenov shale in western Siberia.

Although the contribution of ex-North American shale oil to global production is likely minimal this decade, there could be growth post-2020. The IEA's WEO 2012 sees China producing perhaps 200-k b/d, Argentina at 150-k b/d and a number of other countries producing at sub-100-k b/d levels.

But it should not be surprising that the shale revolution began in the US. The factors behind its success are becoming well understood. The US is fortunate to be endowed with favorable geology and ample water resources, and its geology has been extensively surveyed and developed since the beginnings of the oil industry. A widespread pipeline system minimizes the problem of stranded resources, and even here the scale of production growth is overwhelming legacy infrastructure; but infrastructure is far less developed in many other countries where significant shale resources have been identified. With a well developed hydrocarbons sector, it has access to world-class oil service industry and technically skilled workforce that also support highly entrepreneurial independent upstream companies. The diversity of the private sector supports investment in both large and small projects.

Learning-by-doing, trial and error and incremental innovations by independents have been well suited to the shale development experience so far. The improvements in drilling performance have been in multiple, challenging areas, including individual drilling technologies, integrated drilling workflows, system modeling and prediction and drilling automation. Independents have been able to push gains in production efficiency through faster well construction, improved completions, better efficiency. And service intensity is expected to increase, as these players have sought to optimize specific workflows, integrate improving technologies.

To some extent it has benefited from a determined brute force approach, with the drilling of many wells, many of which turn out to be low productive areas; many completion intervals, which might end up with limited production potential; and stimulation design can see large parts of the fractured rock un-propped. This approach reflects and is reflected in the volatile of outcomes in shale production,

given as-yet limited ability to predict variations in shale quality and with substantial variation in the performance of wells. Maximizing the number of wells and stages has helped find and then further target those sweet spots that are found. But as shale production evolves and matures, the balance of advantages could shift to the majors, though this could yet be a slow process. Further technological advances to improve the ability to predict shale variability could reduce the number of poor wells drilled, and reduce the completion of poor intervals. But in the meantime, an active universe of independents and supporting oil services companies seems to be an important ingredient in fast shale development.

In addition, given the cost structure of the shale gas phenomenon, with well's costing between 1/100 and 1/10 of the cost of deepwater drilling, costs of entry are very low. But what is required is a capital markets structure that provides financing to the industry. Typically, upstream allocations in the oil and gas business come from cash flow. But in the US and to some degree in Canada there are low costs to entry and a robust capital market with a 80 year history of financing risky exploration, allowing new entrepreneurial entrants to the business. One characteristic of the entrepreneurship is the granting of decision authority on drilling to drilling managers, which has enabled the independents to experiment with techniques in maximizing efficient use of capital and drilling.

But further to this, the US enjoys a mineral and land rights regime that is particularly conducive to shale development. In most countries in the world mineral rights are owned by the government. In the United States and Canada there is a historical tradition that protects the private property rights of land and mineral owners. This enables the landowners to negotiate what in most other countries is called fiscal terms and conditions and might well be the most critical factor enabling the shale revolution to unfold in North America. The role of the government in earning from mineral rights is much lower in the US and Canada, where private land use means landowners and companies negotiate directly on land access and royalties, rather than royalties imposed from above. Given the variability of shale geology on a relatively small scale, this has allowed for efficient allocation of resources to the most productive areas.

Figure 63. The UK has significant shale resources, a history of production, and good understanding of its geology, but shale could still see a slower pace of uptake there



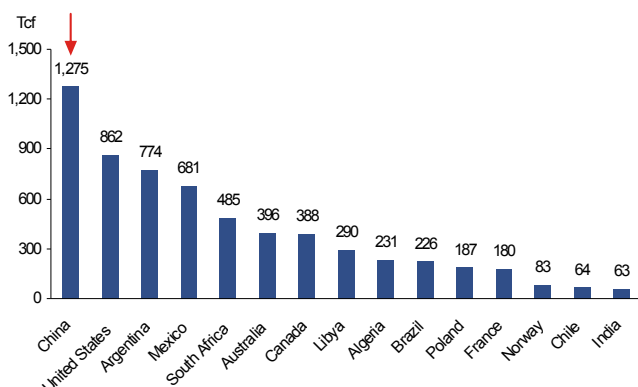
Source: FT, Citi Research

So while the industry structure – an ecosystem of flourishing entrepreneurial independent upstream operators and service companies – is also favorable in the US, Canada and to some extent Australia and the UK, the government role in mineral rights in the latter two countries is a major impediment to shale exploitation. The UK has significant shale reserves – perhaps 20-40 Tcf technically recoverable – and has a history of production and geological understanding, but rigid central government regulations could hold this back. Add to this great concern over the impact of hydraulic fracturing on atypical seismic activity, with a recent history of earthquakes near Blackpool, as well as water pollution issues. However, the application of hydraulic fracturing to offshore North Sea fields could help boost production in the declining region.

China has perhaps the largest shale gas resources outside the US – the EIA estimated 1,275-Tcf, though the Chinese Ministry for Land and Resources' own March 2012 survey sees a smaller but still-substantial 25 tcm (875-Tcf) – and while the government is targeting ambitious growth in shale development, exploration and development have been slow to date. Early indications suggest more challenging geology than that of the major US shale plays to date, against a background of acute water shortages in the most of the major Chinese shale resource areas. Limited experience with the technology and historically limited mapping of resources

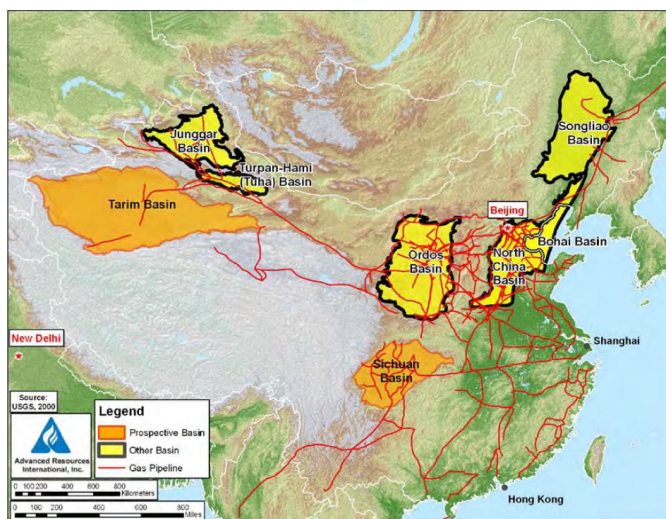
provide further drags, although can be overcome. Also hindering the appetite for development is the lack of pipeline infrastructure to bring new supply to market, and new pipeline construction – and by extension, shale gas development – is not well incentivized by low, government-controlled gas prices. A more restrictive environment for smaller, entrepreneurial independent-like companies could also inhibit the feverish activity and pace of growth seen in the US. For now, Chinese companies' strategies seem to be focusing on gaining domestic acreage, learning from abroad through partnership and acquisition, and waiting until the domestic price control regime becomes favorable.

Figure 64. Estimated global shale gas reserves (technically recoverable, Tcf)



Source: EIA, Citi Research

Figure 65. China shale resources map



Source: EIA, Citi Research

Argentina's shale gas and oil resources hold great geological potential, but fears of heavy handed government involvement in nationalization of assets and control of energy prices suggest slower development of its hydrocarbon wealth. EIA's world shale gas assessment estimated that Argentina has 774-Tcf of technically recoverable shale gas, the third largest assessed in the world after China and the US, though the study did not cover the Middle East and Russia, which are considered to hold substantial resources. An unattractive environment for investment has led to steady declines in oil and gas production, a shrinking exportable oil surplus, and an growing import bill for natural gas.

Figure 66. South American shale resources



Source: EIA

For a while, the government had capped wellhead gas prices at \$2.50/mmbtu, even as producers argued that \$6-8 levels were required to make significant E&P investment in shale gas worthwhile, but just this December, President Cristina Fernandez de Kirchner announced that now-state-controlled YPF would get \$7.50/MMBtu wellhead prices for all "new" gas production, and that other companies could receive the same prices if they promised future "volumes and investment". Fernandez had authorized a three-fold increase in the price of gas used for CNG vehicles. Although a similar easing of price controls on liquids has not followed this announcement, the Argentinian President has reportedly allowed wellhead prices for oil to rise also over the last year, with producers said to be receiving \$75/bbl for domestic Medano crude, up from \$45 last year. End-user retail fuel prices across the country have also been allowed to rise by 3% on average. Export controls for oil remain in an effort to ensure that secure domestic demand, through export taxes and quotas. The latest loosening of wellhead gas prices is a more encouraging sign, but this nevertheless came only half a year after

Fernandez expropriated Repsol's majority stake in YPF, the largest producer in Argentina, highlighting the potentially heady political risk for the kind of international involvement that would help boost shale development in the country.

The EIA assessed Neuquen Basin to hold 407-Tcf of technically recoverable gas, which is twenty times the 21-Tcf estimated in the Eagle Ford play in the US. The Vaca Muerta shale formation may hold 22.8-bn boe of liquids. And international companies have continued to acquire acreage and drill exploratory wells. In the latest of a series of significant developments over the last year, Americas Petrogas announced a shale oil find at the Los Toldos Este well on the Los Toldos 11 block in the Neuquen Basin. The company drilled a vertical well down to depths of 3,000m (9,800ft), hydraulically stimulated with five stages, with an IP rate of 797-boe/d, of which 694-b/d was light, sweet crude with an API gravity of 39.6°. The initial 30-day average flow rate was 309-boe/d, 245-b/d of which was crude oil.

Russia's shale prospects have been receiving increasing attention, with the Energy Ministry proposing incentives and licensing to move the industry forward. But given the huge conventional reserves in situ, and the better economics these reserves offer, development in the near future looks unlikely. The Energy Ministry itself declared that even if Russian shale economics could compete with the best of the US, they would still be more expensive than most of the conventional reserves on offer.

Saudi Arabia has huge incentives to develop shale gas, as there is a great need for more natural gas to displace oil use in power generation. The Kingdom is currently using upwards of 900-k b/d in summer time, and an average of 400-500-k b/d over the year and growing. Energy use is growing is 5-6% per year to satisfy the needs of power generation and the petrochemicals industry. The Kingdom does have huge natural gas reserves but these are mainly associated gas. Like China, Saudi Arabia is short on water, though it does have large desalinization programs. Also like China, Saudi domestic hydrocarbon prices need to be reformed, though the Kingdom does have a big incentive to free-up oil for exports. The country has huge shale potential, with Baker Hughes estimating 645-Tcf, and has announced new drilling programs; pilot programs commissioned by Aramco with \$9bn of committed funding include exploration of the Quesaiba shale in the east, the Nafud basin north of Riyadh, as well as shale resources in the northwest and western parts of the Kingdom. Activity is already ramping up, with five rigs exploring shale gas since early-2012, reaching some 12 rigs now. Another 20 are being tendered for 2013, while a further 20 under consideration. So the motivation to develop shale gas is there, but it remains an open question whether a behemoth like Saudi Aramco can exploit shale successfully; should Saudi Arabia look to bring in independents to develop the sector?

Poland and France have been identified as having shale gas resources, with the EIA assessing 187-Tcf in Poland and 180-Tcf in France, although the Polish Geological Institute has estimated a lower range of 346 bcm to 1.9 tcm (12- to 67-Tcf). Poland is keen to reduce its reliance on Russian gas, and does not face as vociferous environmental opposition, but test wells have not performed well so far, and the search for so-called "sweet spots" continues. Poorer geology, a shortage of rigs, and less favorable tax environment. And if Poland does begin significant shale gas production, it could risk being undercut by Gazprom, at least in incentivized take-or-pay contracts in which Russia could provide additional volumes at a reduced prices. While this could stymie Polish production, it would still be a net positive for reducing gas prices, and further weakening Russian-set oil-indexed prices in Europe. In France, which could have a larger resource base than Poland, environmental opposition to hydraulic fracturing is strong; French shale gas looks unlikely this decade.

Appendix A-1

Analyst Certification

The research analyst(s) primarily responsible for the preparation and content of this research report are named in bold text in the author block at the front of the product except for those sections where an analyst's name appears in bold alongside content which is attributable to that analyst. Each of these analyst(s) certify, with respect to the section(s) of the report for which they are responsible, that the views expressed therein accurately reflect their personal views about each issuer and security referenced and were prepared in an independent manner, including with respect to Citigroup Global Markets Inc and its affiliates. No part of the research analyst's compensation was, is, or will be, directly or indirectly, related to the specific recommendation(s) or view(s) expressed by that research analyst in this report.

IMPORTANT DISCLOSURES

Analysts' compensation is determined based upon activities and services intended to benefit the investor clients of Citigroup Global Markets Inc. and its affiliates ("the Firm"). Like all Firm employees, analysts receive compensation that is impacted by overall firm profitability which includes investment banking revenues.

For important disclosures (including copies of historical disclosures) regarding the companies that are the subject of this Citi Research product ("the Product"), please contact Citi Research, 388 Greenwich Street, 28th Floor, New York, NY, 10013, Attention: Legal/Compliance [E6WYB6412478]. In addition, the same important disclosures, with the exception of the Valuation and Risk assessments and historical disclosures, are contained on the Firm's disclosure website at https://www.citivelocity.com/cvr/eppublic/citi_research_disclosures. Valuation and Risk assessments can be found in the text of the most recent research note/report regarding the subject company. Historical disclosures (for up to the past three years) will be provided upon request.

Citi Research Ratings Distribution

Data current as of 4 Oct 2012	12 Month Rating			Relative Rating		
	Buy	Hold	Sell	Buy	Hold	Sell
Citi Research Global Fundamental Coverage	51%	38%	11%	7%	85%	7%
% of companies in each rating category that are investment banking clients	50%	47%	45%	59%	47%	50%

Guide to Citi Research Fundamental Research Investment Ratings:

Citi Research stock recommendations include an investment rating and an optional risk rating to highlight high risk stocks.

Risk rating takes into account both price volatility and fundamental criteria. Stocks will either have no risk rating or a High risk rating assigned.

Investment Ratings: Citi Research investment ratings are Buy, Neutral and Sell. Our ratings are a function of analyst expectations of expected total return ("ETR") and risk. ETR is the sum of the forecast price appreciation (or depreciation) plus the dividend yield for a stock within the next 12 months. The Investment rating definitions are: Buy (1) ETR of 15% or more or 25% or more for High risk stocks; and Sell (3) for negative ETR. Any covered stock not assigned a Buy or a Sell is a Neutral (2). For stocks rated Neutral (2), if an analyst believes that there are insufficient valuation drivers and/or investment catalysts to derive a positive or negative investment view, they may elect with the approval of Citi Research management not to assign a target price and, thus, not derive an ETR. Analysts may place covered stocks "Under Review" in response to exceptional circumstances (e.g. lack of information critical to the analyst's thesis) affecting the company and / or trading in the company's securities (e.g. trading suspension). As soon as practically possible, the analyst will publish a note re-establishing a rating and investment thesis. To satisfy regulatory requirements, we correspond Under Review and Neutral to Hold in our ratings distribution table for our 12-month fundamental rating system. However, we reiterate that we do not consider Under Review to be a recommendation.

Relative three-month ratings: Citi Research may also assign a three-month relative call (or rating) to a stock to highlight expected out-performance (most preferred) or under-performance (least preferred) versus the geographic and industry sector over a 3 month period. The relative call may highlight a specific near-term catalyst or event impacting the company or the market that is anticipated to have a short-term price impact on the equity securities of the company. Absent any specific catalyst the analyst(s) will indicate the most and least preferred stocks in the universe of stocks under consideration, explaining the basis for this short-term view. This three-month view may be different from and does not affect a stock's fundamental equity rating, which reflects a longer-term total absolute return expectation. For purposes of NASD/NYSE ratings-distribution-disclosure rules, most preferred calls correspond to a buy recommendation and least preferred calls correspond to a sell recommendation. Any stock not assigned to a most preferred or least preferred call is considered non-relative-rated (NRR). For purposes of NASD/NYSE ratings-distribution-disclosure rules we correspond NRR to Hold in our ratings distribution table for our 3-month relative rating system. However, we reiterate that we do not consider NRR to be a recommendation.

Prior to October 8, 2011, the firm's stock recommendation system included a risk rating and an investment rating. **Risk ratings**, which took into account both price volatility and fundamental criteria, were: Low (L), Medium (M), High (H), and Speculative (S). **Investment Ratings** of Buy, Hold and Sell were a function of the Citi Research expectation of total return (forecast price appreciation and dividend yield within the next 12 months) and risk rating. Additionally, analysts could have placed covered stocks "Under Review" in response to exceptional circumstances (e.g. lack of information critical to the analyst's thesis) affecting the company and/or trading in the company's securities (e.g. trading suspension). Stocks placed "Under Review" were monitored daily by management and as practically possible, the analyst published a note re-establishing a rating and investment thesis. For securities in developed markets (US, UK, Europe, Japan, and Australia/New Zealand), investment ratings were: Buy (1) (expected total return of 10% or more for Low-Risk stocks, 15% or more for Medium-Risk stocks, 20% or more for High-Risk stocks, and 35% or more for Speculative stocks); Hold (2) (0%-10% for Low-Risk stocks, 0%-15% for Medium-Risk stocks, 0%-20% for High-Risk stocks, and 0%-35% for Speculative stocks); and Sell (3) (negative total return). For securities in emerging markets (Asia Pacific, Emerging Europe/Middle East/Africa, and Latin America), investment ratings were: Buy (1) (expected total return of 15% or more for Low-Risk stocks, 20% or more for Medium-Risk stocks, 30% or more for High-Risk stocks, and 40% or more for Speculative stocks); Hold (2) (5%-15% for Low-Risk stocks, 10%-20% for Medium-Risk stocks, 15%-30% for High-Risk stocks, and 20%-40% for Speculative stocks); and Sell (3) (5% or less for Low-Risk stocks, 10% or less for Medium-Risk stocks, 15% or less for High-Risk stocks, and 20% or less for Speculative stocks).

Investment ratings are determined by the ranges described above at the time of initiation of coverage, a change in investment and/or risk rating, or a change in target price (subject to limited management discretion). At other times, the expected total returns may fall outside of these ranges because of market price movements and/or other short-term volatility or trading patterns. Such interim deviations from specified ranges will be permitted but will become subject to

review by Research Management. Your decision to buy or sell a security should be based upon your personal investment objectives and should be made only after evaluating the stock's expected performance and risk.

NON-US RESEARCH ANALYST DISCLOSURES

Non-US research analysts who have prepared this report (i.e., all research analysts listed below other than those identified as employed by Citigroup Global Markets Inc.) are not registered/qualified as research analysts with FINRA. Such research analysts may not be associated persons of the member organization and therefore may not be subject to the NYSE Rule 472 and NASD Rule 2711 restrictions on communications with a subject company, public appearances and trading securities held by a research analyst account. The legal entities employing the authors of this report are listed below:

Citigroup Global Markets Inc

Anthony Yuen; Edward L Morse; Eric G Lee; Daniel P Ahn; Aakash Doshi

Citigroup Global Markets Ltd

Seth M Kleinman

OTHER DISCLOSURES

For securities recommended in the Product in which the Firm is not a market maker, the Firm is a liquidity provider in the issuers' financial instruments and may act as principal in connection with such transactions. The Firm is a regular issuer of traded financial instruments linked to securities that may have been recommended in the Product. The Firm regularly trades in the securities of the issuer(s) discussed in the Product. The Firm may engage in securities transactions in a manner inconsistent with the Product and, with respect to securities covered by the Product, will buy or sell from customers on a principal basis.

Securities recommended, offered, or sold by the Firm: (i) are not insured by the Federal Deposit Insurance Corporation; (ii) are not deposits or other obligations of any insured depository institution (including Citibank); and (iii) are subject to investment risks, including the possible loss of the principal amount invested. Although information has been obtained from and is based upon sources that the Firm believes to be reliable, we do not guarantee its accuracy and it may be incomplete and condensed. Note, however, that the Firm has taken all reasonable steps to determine the accuracy and completeness of the disclosures made in the Important Disclosures section of the Product. The Firm's research department has received assistance from the subject company(ies) referred to in this Product including, but not limited to, discussions with management of the subject company(ies). Firm policy prohibits research analysts from sending draft research to subject companies. However, it should be presumed that the author of the Product has had discussions with the subject company to ensure factual accuracy prior to publication. All opinions, projections and estimates constitute the judgment of the author as of the date of the Product and these, plus any other information contained in the Product, are subject to change without notice. Prices and availability of financial instruments also are subject to change without notice. Notwithstanding other departments within the Firm advising the companies discussed in this Product, information obtained in such role is not used in the preparation of the Product. Although Citi Research does not set a predetermined frequency for publication, if the Product is a fundamental research report, it is the intention of Citi Research to provide research coverage of the/those issuer(s) mentioned therein, including in response to news affecting this issuer, subject to applicable quiet periods and capacity constraints. The Product is for informational purposes only and is not intended as an offer or solicitation for the purchase or sale of a security. Any decision to purchase securities mentioned in the Product must take into account existing public information on such security or any registered prospectus.

Investing in non-U.S. securities, including ADRs, may entail certain risks. The securities of non-U.S. issuers may not be registered with, nor be subject to the reporting requirements of the U.S. Securities and Exchange Commission. There may be limited information available on foreign securities. Foreign companies are generally not subject to uniform audit and reporting standards, practices and requirements comparable to those in the U.S. Securities of some foreign companies may be less liquid and their prices more volatile than securities of comparable U.S. companies. In addition, exchange rate movements may have an adverse effect on the value of an investment in a foreign stock and its corresponding dividend payment for U.S. investors. Net dividends to ADR investors are estimated, using withholding tax rates conventions, deemed accurate, but investors are urged to consult their tax advisor for exact dividend computations. Investors who have received the Product from the Firm may be prohibited in certain states or other jurisdictions from purchasing securities mentioned in the Product from the Firm. Please ask your Financial Consultant for additional details. Citigroup Global Markets Inc. takes responsibility for the Product in the United States. Any orders by US investors resulting from the information contained in the Product may be placed only through Citigroup Global Markets Inc.

Important Disclosures for Morgan Stanley Smith Barney LLC Customers: Morgan Stanley & Co. LLC (Morgan Stanley) research reports may be available about the companies that are the subject of this Citi Research research report. Ask your Financial Advisor or use smithbarney.com to view any available Morgan Stanley research reports in addition to Citi Research research reports.

Important disclosure regarding the relationship between the companies that are the subject of this Citi Research research report and Morgan Stanley Smith Barney LLC and its affiliates are available at the Morgan Stanley Smith Barney disclosure website at www.morganstanleysmithbarney.com/researchdisclosures.

For Morgan Stanley and Citigroup Global Markets, Inc. specific disclosures, you may refer to www.morganstanley.com/researchdisclosures and https://www.citivelocity.com/cvr/epublic/citi_research_disclosures.

This Citi Research research report has been reviewed and approved on behalf of Morgan Stanley Smith Barney LLC. This review and approval was conducted by the same person who reviewed this research report on behalf of Citi Research. This could create a conflict of interest.

The Citigroup legal entity that takes responsibility for the production of the Product is the legal entity which the first named author is employed by. The Product is made available in **Australia** through Citi Global Markets Australia Pty Ltd. (ABN 64 003 114 832 and AFSL No. 240992), participant of the ASX Group and regulated by the Australian Securities & Investments Commission. Citigroup Centre, 2 Park Street, Sydney, NSW 2000. The Product is made available in Australia to Private Banking wholesale clients through Citigroup Pty Limited (ABN 88 004 325 080 and AFSL 238098). Citigroup Pty Limited provides all financial product advice to Australian Private Banking wholesale clients through bankers and relationship managers. If there is any doubt about the suitability of investments held in Citigroup Private Bank accounts, investors should contact the Citigroup Private Bank in Australia. Citigroup companies may compensate affiliates and their representatives for providing products and services to clients. The Product is made available in **Brazil** by Citigroup Global Markets Brasil - CCTVM SA, which is regulated by CVM - Comissão de Valores Mobiliários, BACEN - Brazilian Central Bank, APIMEC - Associação dos Analistas e Profissionais de Investimento do Mercado de Capitais and ANBID - Associação Nacional dos Bancos de Investimento. Av. Paulista, 1111 - 11º andar - CEP. 01311920 - São Paulo - SP. If the Product is being made available in certain provinces of **Canada** by Citigroup Global Markets (Canada) Inc. ("CGM Canada"), CGM Canada has approved the Product. Citigroup Place, 123 Front Street West, Suite 1100, Toronto, Ontario M5J

2M3. This product is available in **Chile** through Banchile Corredores de Bolsa S.A., an indirect subsidiary of Citigroup Inc., which is regulated by the Superintendencia de Valores y Seguros. Agustinas 975, piso 2, Santiago, Chile. The Product is made available in **France** by Citigroup Global Markets Limited, which is authorised and regulated by Financial Services Authority. 1-5 Rue Paul Cézanne, 8ème, Paris, France. The Product is distributed in **Germany** by Citigroup Global Markets Deutschland AG ("CGMD"), which is regulated by Bundesanstalt fuer Finanzdienstleistungsaufsicht (BaFin). CGMD, Reuterweg 16, 60323 Frankfurt am Main. Research which relates to "securities" (as defined in the Securities and Futures Ordinance (Cap. 571 of the Laws of Hong Kong)) is issued in **Hong Kong** by, or on behalf of, Citigroup Global Markets Asia Limited which takes full responsibility for its content. Citigroup Global Markets Asia Ltd. is regulated by Hong Kong Securities and Futures Commission. If the Research is made available through Citibank, N.A., Hong Kong Branch, for its clients in Citi Private Bank, it is made available by Citibank N.A., Citibank Tower, Citibank Plaza, 3 Garden Road, Hong Kong. Citibank N.A. is regulated by the Hong Kong Monetary Authority. Please contact your Private Banker in Citibank N.A., Hong Kong, Branch if you have any queries on or any matters arising from or in connection with this document. The Product is made available in **India** by Citigroup Global Markets India Private Limited, which is regulated by Securities and Exchange Board of India. Bakhtawar, Nariman Point, Mumbai 400-021. The Product is made available in **Indonesia** through PT Citigroup Securities Indonesia. 5/F, Citibank Tower, Bapindo Plaza, Jl. Jend. Sudirman Kav. 54-55, Jakarta 12190. Neither this Product nor any copy hereof may be distributed in Indonesia or to any Indonesian citizens wherever they are domiciled or to Indonesian residents except in compliance with applicable capital market laws and regulations. This Product is not an offer of securities in Indonesia. The securities referred to in this Product have not been registered with the Capital Market and Financial Institutions Supervisory Agency (BAPEPAM-LK) pursuant to relevant capital market laws and regulations, and may not be offered or sold within the territory of the Republic of Indonesia or to Indonesian citizens through a public offering or in circumstances which constitute an offer within the meaning of the Indonesian capital market laws and regulations. The Product is made available in **Israel** through Citibank NA, regulated by the Bank of Israel and the Israeli Securities Authority. Citibank, N.A. Platinum Building, 21 Ha'arba'ah St, Tel Aviv, Israel. The Product is made available in **Italy** by Citigroup Global Markets Limited, which is authorised and regulated by Financial Services Authority. Via dei Mercanti, 12, Milan, 20121, Italy. The Product is made available in **Japan** by Citigroup Global Markets Japan Inc. ("CGMJ"), which is regulated by Financial Services Agency, Securities and Exchange Surveillance Commission, Japan Securities Dealers Association, Tokyo Stock Exchange and Osaka Securities Exchange. Shin-Marunouchi Building, 1-5-1 Marunouchi, Chiyoda-ku, Tokyo 100-6520 Japan. If the Product was distributed by SMBC Nikko Securities Inc. it is being so distributed under license. In the event that an error is found in an CGMJ research report, a revised version will be posted on the Firm's Citi Velocity website. If you have questions regarding Citi Velocity, please call (81 3) 6270-3019 for help. The Product is made available in **Korea** by Citigroup Global Markets Korea Securities Ltd., which is regulated by the Financial Services Commission, the Financial Supervisory Service and the Korea Financial Investment Association (KOFIA). Citibank Building, 39 Da-dong, Jung-gu, Seoul 100-180, Korea. KOFIA makes available registration information of research analysts on its website. Please visit the following website if you wish to find KOFIA registration information on research analysts of Citigroup Global Markets Korea Securities Ltd. <http://dis.kofia.or.kr/fs/dis2/fundMgr/DISFundMgrAnalystPop.jsp?companyCd2=A03030&pageDiv=02>. The Product is made available in Korea by Citibank Korea Inc., which is regulated by the Financial Services Commission and the Financial Supervisory Service. Address is Citibank Building, 39 Da-dong, Jung-gu, Seoul 100-180, Korea. The Product is made available in **Malaysia** by Citigroup Global Markets Malaysia Sdn Bhd (Company No. 460819-D) ("CGMM") to its clients and CGMM takes responsibility for its contents. CGMM is regulated by the Securities Commission of Malaysia. Please contact CGMM at Level 43 Menara Citibank, 165 Jalan Ampang, 50450 Kuala Lumpur, Malaysia in respect of any matters arising from, or in connection with, the Product. The Product is made available in **Mexico** by Acciones y Valores Banamex, S.A. De C. V., Casa de Bolsa, Integrante del Grupo Financiero Banamex ("Accival") which is a wholly owned subsidiary of Citigroup Inc. and is regulated by Comision Nacional Bancaria y de Valores. Reforma 398, Col. Juarez, 06600 Mexico, D.F. In **New Zealand** the Product is made available to 'wholesale clients' only as defined by s5C(1) of the Financial Advisers Act 2008 ("FAA") through Citigroup Global Markets Australia Pty Ltd (ABN 64 003 114 832 and AFSL No. 240992), an overseas financial adviser as defined by the FAA, participant of the ASX Group and regulated by the Australian Securities & Investments Commission. Citigroup Centre, 2 Park Street, Sydney, NSW 2000. The Product is made available in **Pakistan** by Citibank N.A. Pakistan branch, which is regulated by the State Bank of Pakistan and Securities Exchange Commission, Pakistan. AWT Plaza, 1.1. Chundrigar Road, P.O. Box 4889, Karachi-74200. The Product is made available in the **Philippines** through Citicorp Financial Services and Insurance Brokerage Philippines, Inc., which is regulated by the Philippines Securities and Exchange Commission. 20th Floor Citibank Square Bldg. The Product is made available in the Philippines through Citibank NA Philippines branch, Citibank Tower, 8741 Paseo De Roxas, Makati City, Manila. Citibank NA Philippines NA is regulated by The Bangko Sentral ng Pilipinas. The Product is made available in **Poland** by Dom Maklerski Banku Handlowego SA an indirect subsidiary of Citigroup Inc., which is regulated by Komisja Nadzoru Finansowego. Dom Maklerski Banku Handlowego S.A. ul.Senatorska 16, 00-923 Warszawa. The Product is made available in the **Russian Federation** through ZAO Citibank, which is licensed to carry out banking activities in the Russian Federation in accordance with the general banking license issued by the Central Bank of the Russian Federation and brokerage activities in accordance with the license issued by the Federal Service for Financial Markets. Neither the Product nor any information contained in the Product shall be considered as advertising the securities mentioned in this report within the territory of the Russian Federation or outside the Russian Federation. The Product does not constitute an appraisal within the meaning of the Federal Law of the Russian Federation of 29 July 1998 No. 135-FZ (as amended) On Appraisal Activities in the Russian Federation. 8-10 Gasheka Street, 125047 Moscow. The Product is made available in **Singapore** through Citigroup Global Markets Singapore Pte. Ltd. ("CGMSPL"), a capital markets services license holder, and regulated by Monetary Authority of Singapore. Please contact CGMSPL at 8 Marina View, 21st Floor Asia Square Tower 1, Singapore 018960, in respect of any matters arising from, or in connection with, the analysis of this document. This report is intended for recipients who are accredited, expert and institutional investors as defined under the Securities and Futures Act (Cap. 289). The Product is made available by The Citigroup Private Bank in Singapore through Citibank, N.A., Singapore Branch, a licensed bank in Singapore that is regulated by Monetary Authority of Singapore. Please contact your Private Banker in Citibank N.A., Singapore Branch if you have any queries on or any matters arising from or in connection with this document. This report is intended for recipients who are accredited, expert and institutional investors as defined under the Securities and Futures Act (Cap. 289). This report is distributed in Singapore by Citibank Singapore Ltd ("CSL") to selected Citigold/Citigold Private Clients. CSL provides no independent research or analysis of the substance or in preparation of this report. Please contact your Citigold/Citigold Private Client Relationship Manager in CSL if you have any queries on or any matters arising from or in connection with this report. This report is intended for recipients who are accredited investors as defined under the Securities and Futures Act (Cap. 289). Citigroup Global Markets (Pty) Ltd. is incorporated in the **Republic of South Africa** (company registration number 2000/025866/07) and its registered office is at 145 West Street, Sandton, 2196, Saxonwold. Citigroup Global Markets (Pty) Ltd. is regulated by JSE Securities Exchange South Africa, South African Reserve Bank and the Financial Services Board. The investments and services contained herein are not available to private customers in South Africa. The Product is made available in **Spain** by Citigroup Global Markets Limited, which is authorised and regulated by Financial Services Authority. 29 Jose Ortega Y Gasset, 4th Floor, Madrid, 28006, Spain. The Product is made available in the **Republic of China** through Citigroup Global Markets Taiwan Securities

Company Ltd. ("CGMTS"), 14 and 15F, No. 1, Songzhi Road, Taipei 110, Taiwan and/or through Citibank Securities (Taiwan) Company Limited ("CSTL"), 14 and 15F, No. 1, Songzhi Road, Taipei 110, Taiwan, subject to the respective license scope of each entity and the applicable laws and regulations in the Republic of China. CGMTS and CSTL are both regulated by the Securities and Futures Bureau of the Financial Supervisory Commission of Taiwan, the Republic of China. No portion of the Product may be reproduced or quoted in the Republic of China by the press or any third parties [without the written authorization of CGMTS and CSTL]. If the Product covers securities which are not allowed to be offered or traded in the Republic of China, neither the Product nor any information contained in the Product shall be considered as advertising the securities or making recommendation of the securities in the Republic of China. The Product is for informational purposes only and is not intended as an offer or solicitation for the purchase or sale of a security or financial products. Any decision to purchase securities or financial products mentioned in the Product must take into account existing public information on such security or the financial products or any registered prospectus. The Product is made available in **Thailand** through Citicorp Securities (Thailand) Ltd., which is regulated by the Securities and Exchange Commission of Thailand. 18/F, 22/F and 29/F, 82 North Sathorn Road, Silom, Bangrak, Bangkok 10500, Thailand. The Product is made available in **Turkey** through Citibank AS which is regulated by Capital Markets Board. Tekfen Tower, Eski Buyukdere Caddesi # 209 Kat 2B, 23294 Levent, Istanbul, Turkey. In the **U.A.E.**, these materials (the "Materials") are communicated by Citigroup Global Markets Limited, DIFC branch ("CGML"), an entity registered in the Dubai International Financial Center ("DIFC") and licensed and regulated by the Dubai Financial Services Authority ("DFSA") to Professional Clients and Market Counterparties only and should not be relied upon or distributed to Retail Clients. A distribution of the different Citi Research ratings distribution, in percentage terms for Investments in each sector covered is made available on request. Financial products and/or services to which the Materials relate will only be made available to Professional Clients and Market Counterparties. The Product is made available in **United Kingdom** by Citigroup Global Markets Limited, which is authorised and regulated by Financial Services Authority. This material may relate to investments or services of a person outside of the UK or to other matters which are not regulated by the FSA and further details as to where this may be the case are available upon request in respect of this material. Citigroup Centre, Canada Square, Canary Wharf, London, E14 5LB. The Product is made available in **United States** by Citigroup Global Markets Inc, which is a member of FINRA and registered with the US Securities and Exchange Commission. 388 Greenwich Street, New York, NY 10013. Unless specified to the contrary, within EU Member States, the Product is made available by Citigroup Global Markets Limited, which is regulated by Financial Services Authority.

Pursuant to Comissão de Valores Mobiliários Rule 483, Citi is required to disclose whether a Citi related company or business has a commercial relationship with the subject company. Considering that Citi operates multiple businesses in more than 100 countries around the world, it is likely that Citi has a commercial relationship with the subject company.

Many European regulators require that a firm must establish, implement and make available a policy for managing conflicts of interest arising as a result of publication or distribution of investment research. The policy applicable to Citi Research's Products can be found at https://www.citivelocity.com/cvr/eppublic/citi_research_disclosures.

Compensation of equity research analysts is determined by equity research management and Citigroup's senior management and is not linked to specific transactions or recommendations.

The Product may have been distributed simultaneously, in multiple formats, to the Firm's worldwide institutional and retail customers. The Product is not to be construed as providing investment services in any jurisdiction where the provision of such services would not be permitted.

Subject to the nature and contents of the Product, the investments described therein are subject to fluctuations in price and/or value and investors may get back less than originally invested. Certain high-volatility investments can be subject to sudden and large falls in value that could equal or exceed the amount invested. Certain investments contained in the Product may have tax implications for private customers whereby levels and basis of taxation may be subject to change. If in doubt, investors should seek advice from a tax adviser. The Product does not purport to identify the nature of the specific market or other risks associated with a particular transaction. Advice in the Product is general and should not be construed as personal advice given it has been prepared without taking account of the objectives, financial situation or needs of any particular investor. Accordingly, investors should, before acting on the advice, consider the appropriateness of the advice, having regard to their objectives, financial situation and needs. Prior to acquiring any financial product, it is the client's responsibility to obtain the relevant offer document for the product and consider it before making a decision as to whether to purchase the product. With the exception of our product that is made available only to Qualified Institutional Buyers (QIBs) and other product that is made available through other distribution channels only to certain categories of clients to satisfy legal or regulatory requirements, Citi Research concurrently disseminates its research via proprietary and non-proprietary electronic distribution platforms. Periodically, individual Citi Research analysts may also opt to circulate research posted on such platforms to one or more clients by email. Such email distribution is discretionary and is done only after the research has been disseminated via the aforementioned distribution channels. Citi Research simultaneously distributes product that is limited to QIBs only through email distribution.

The level and types of services provided by Citi Research analysts to clients may vary depending on various factors such as the client's individual preferences as to the frequency and manner of receiving communications from analysts, the client's risk profile and investment focus and perspective (e.g. market-wide, sector specific, long term, short-term etc.), the size and scope of the overall client relationship with Citi and legal and regulatory constraints. Citi Research product may source data from dataCentral. dataCentral is a Citi Research proprietary database, which includes Citi estimates, data from company reports and feeds from Reuters and Datastream.

© 2012 Citigroup Global Markets Inc. Citi Research is a division of Citigroup Global Markets Inc. Citi and Citi with Arc Design are trademarks and service marks of Citigroup Inc. and its affiliates and are used and registered throughout the world. All rights reserved. Any unauthorized use, duplication, redistribution or disclosure of this report (the "Product"), including, but not limited to, redistribution of the Product by electronic mail, posting of the Product on a website or page, and/or providing to a third party a link to the Product, is prohibited by law and will result in prosecution. The information contained in the Product is intended solely for the recipient and may not be further distributed by the recipient to any third party. Where included in this report, MSCI sourced information is the exclusive property of Morgan Stanley Capital International Inc. (MSCI). Without prior written permission of MSCI, this information and any other MSCI intellectual property may not be reproduced, redisseminated or used to create any financial products, including any indices. This information is provided on an "as is" basis. The user assumes the entire risk of any use made of this information. MSCI, its affiliates and any third party involved in, or related to, computing or compiling the information hereby expressly disclaim all warranties of originality, accuracy, completeness, merchantability or fitness for a particular purpose with respect to any of this information. Without limiting any of the foregoing, in no event shall MSCI, any of its affiliates or any third party involved in, or related to, computing or compiling the information have any liability for any damages of any kind. MSCI, Morgan Stanley Capital International and the MSCI indexes are services marks of MSCI and its affiliates. The Firm accepts no liability whatsoever for the actions of third parties. The Product may provide the addresses of, or contain hyperlinks to, websites. Except to the extent to which the Product refers to website material of the Firm, the Firm has not reviewed the linked site. Equally, except to the extent to which the Product refers to website material of the Firm, the Firm takes no

responsibility for, and makes no representations or warranties whatsoever as to, the data and information contained therein. Such address or hyperlink (including addresses or hyperlinks to website material of the Firm) is provided solely for your convenience and information and the content of the linked site does not in anyway form part of this document. Accessing such website or following such link through the Product or the website of the Firm shall be at your own risk and the Firm shall have no liability arising out of, or in connection with, any such referenced website.

ADDITIONAL INFORMATION IS AVAILABLE UPON REQUEST
