

The New American (Gas) Century

Transforming Sectors, Redefining the Global Natural Gas Order and Setting New Long Term Prices



- **Mid-\$5/MMBtu should be the long term US gas price range**, above marginal production costs and ~20 to 25% above current forwards out to 2020, as demand surges between now and then. Short term production costs should set a soft price floor at ~\$4; power generation/exports economics put a soft price ceiling at ~\$6 to 7.
- **Mushrooming demand, starting in 2015-16, should be the price mover.** US gas demand in five sectors – global LNG exports, pipeline exports to Mexico/Canada, industrials, transportation and residential/commercial heating – could climb by at least 23-Bcf/d from 73-Bcf/d, or a 33% rise from 2013 to 2020. By then, 8 to 10-Bcf/d of US LNG exports could make up more than 20% of the global LNG market, remaking the rules of global trade.
- **To raise production to meet demand, gas prices would have to rise to get shale gas drilling moving again**, particularly in enticing firms with both oil/liquids and gas shales to return to gas. This price hinges on the long run oil vs. gas price relationship (e.g. \$5.5/MMBtu gas at \$90/bbl WTI oil). **The market's belief that low short term marginal production costs should bring down long term prices misses the critical impact of market structure, switching costs and severe regional supply-demand imbalances.** Production costs have fallen with efficiency gains; the forward curve is depressed due largely to producers hedging. [But as the 2013-14 winter shows](#), a tight market could quickly drive up prices from depressed levels. Citi examined switching costs from oil to gas plays in setting prices. New entrants without shale acreages face higher cost considerations as well.
- **At this price, the US should still be a competitive LNG and pipeline gas exporter, joining the ranks of the major gas suppliers globally.** US LNG exports could surpass Qatar/Australia without counting a tripling of US exports to Mexico.
- **US LNG exports are expected to redefine pricing and structure in the global LNG markets.** Global LNG prices would likely fall and major gas producers that rely on high global prices could lose bargaining power. The breaking of decades-old oligopolies should boost supply and lower prices further. With US LNG having no destination restrictions, a robust spot LNG market is expected to emerge. As the US evolves from a net gas importer into one of the largest exporters, current gas importers should win big but existing exporters face structural challenges.
- **Meanwhile, a mid-\$5 price could still be a sweet spot for many end-use sectors.** Valuations of many utility companies fell partly due to low forward gas prices. Utilities could benefit as higher gas prices push up power prices, widening profit margins. *Ironically, gas demand for power generation may not be a major demand mover.* Industrials should remain very competitive as prices around \$5 would still be much below long term prices in Europe and Asia, and below the \$15 gas-equivalent price of oil at \$90/bbl.

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

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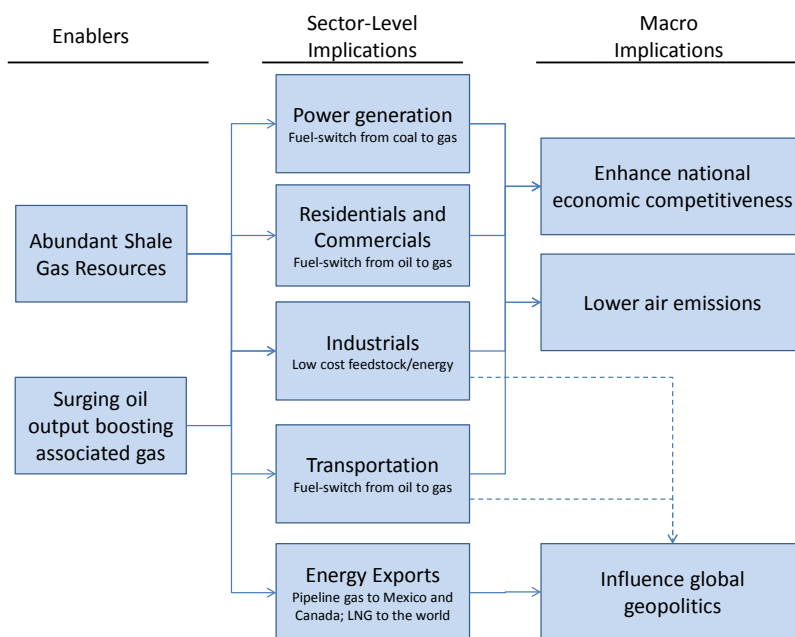
Long term US gas price could be around mid-\$5/MMBtu, well above production cost of most shale gas plays

Besides power generation, the shale gas revolution is about to transform the industrials, transport and export sectors

Long term US natural gas prices look likely to settle in the mid-\$5/MMBtu range (see Section 5 for an in-depth discussion of price formation), above production costs at marginal gas fields, with prices boosted initially by an expected surge in demand at home and for US exports. Triggering a sustainable price increase requires – and results from – a boost in demand, which we expect to mushroom starting in 2015-16. To raise production to meet demand, prices would have to rise to entice firms with both shale oil/liquids and shale gas properties to switch back to gas drilling. In addition, shale gas production growth from the Marcellus and Utica shales in the Northeast, which have supported production growth in recent years, may not be as strong as optimists would believe due to insufficient pipeline takeaway capacity to alleviate the production glut. Other regions, mainly the Gulf Coast, would have to produce more to accommodate demand growth from industrials and exports. Northeast gas prices could remain well below that of the Henry Hub benchmark on the Gulf Coast for some time.

While the natural gas revolution is already impacting many sectors in North America, fundamental transformation is yet to come. Beyond improving industrial competitiveness and promoting fuel-switching in the residential/commercial sector, natural gas could erode oil's dominance in transportation and usher in a tectonic shift in the fortunes of key gas producers and consumers worldwide through North American gas exports via pipeline or LNG. The growth of gas demand for power generation could also be significant initially, but stagnant electricity demand growth amid rising generation from renewables could alter the picture later in the decade.

Figure 1. The shale natural gas and oil revolution: enablers and sector/macro implications

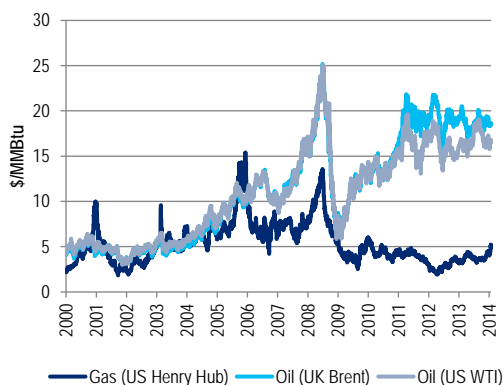


Source: Citi Research

Price arbitrage is the core driver of this economy-wide transformation, with subsequent impacts on global geopolitics. Whether the main US gas price (Henry Hub) is \$3 or \$5/MMBtu, these price levels still offer substantial advantages

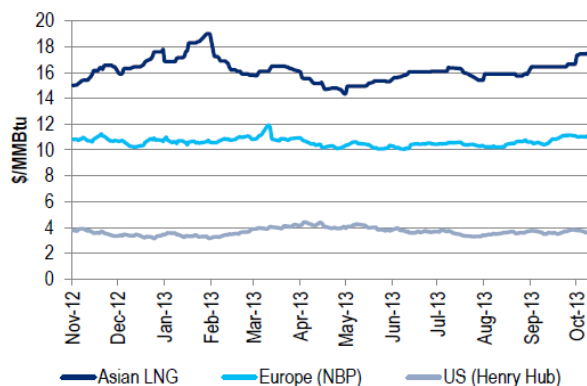
over a heat content-adjusted oil price of around \$16 to \$19/MMBtu, European gas (e.g. NBP) prices at around \$9 to \$11/MMBtu and Asian liquefied natural gas (LNG) price of around \$15 to \$18/MMBtu.

Figure 2. Wide gap between oil and gas prices to drive fuel-switching... (prices from 1999 to 2014)



Source: Bloomberg, Citi Research

Figure 3. ...Differences between global and US gas prices to spur growth of US gas exports (prices from Nov'12 to Nov'13)



Source: Bloomberg, Citi Research

Policy support

Leveraging natural gas to power the economy and raising gas production have broad policy support

This natural gas-driven transformation also appears to be receiving policy support, although there is lots of ambiguity in the way the DOE has qualified acceptance of LNG exports and the emphasis placed on price impacts. It should be noted that pipeline exports to Mexico will in the medium term overshadow LNG exports and these exports don't require significant policy review. In particular, President Obama's new Climate Action Plan¹ - effectively his energy policy - is highly supportive of renewables but also natural gas. The plan essentially calls for the increased use of natural gas in multiple sectors: industrial production, electricity generation, transport and exports. Citi analyzed the plan in the report "[Much ado about climate change](#)" (Jun 25, 2013) Imposing limits on power plant emissions and phasing out fossil fuel subsidies may have the most impact on coal. Natural gas-fired generation would partially substitute the decrease in coal generation and act as backup to renewables. The Plan encourages the adoption of heavy duty natural gas vehicles and the use of alternative fuels in general. In an effort to encourage fuel switching from coal to gas globally and developing a global market for gas, US gas exports should play a key role adding to supply worldwide, turning the US into a net natural gas exporter well before 2020. Exports of lower-cost US gas should bring down LNG prices globally and encouraging fuel switching to gas. President Obama placed heavy emphasis on the use of natural gas in powering the US economy in his annual State of the Union address (Jan 28, 2014).

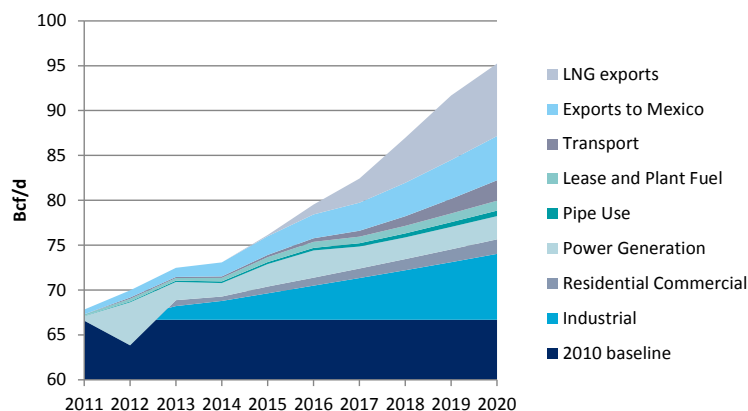
The US natural gas supply-demand balance

US domestic gas demand and exports could rise by 22.9-Bcf/d from 2013 to 2020: just under half of Europe's demand

Natural gas production was the starting point of the game-changing shale revolution. But then as demand growth is accelerating on the prospect of relatively low gas prices for years to come, "demand," which consists of domestic consumption and net exports, could rise by 29-Bcf/d (15.3-Bcf/d domestic + 13.7-Bcf/d exports) between 2010 and 2020. Between 2013 and 2020, "demand" could rise by 22.6-Bcf/d.

¹ <http://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf>

Figure 4. Gas demand to rise due to higher domestic consumption and exports (2011-2020)



Source: EIA, Citi Research

Industrial demand could grow by 7.3-Bcf/d between 2010 and 2020, or 5.8-Bcf/d between 2013 and 2020. Besides petrochemical, steel/primary metals and fertilizers, consumption by a number of sectors due to organic growth and fuel switching from oil or coal to gas should rise sharply. For example, refineries are using more gas to make hydrogen and as an energy source on its own.

Transport could grow by 2.3-Bcf/d between 2010 and 2020, or 2.2-Bcf/d between 2013 and 2020, with nearly 20% market penetration in the heavy-duty trucking sector.

Power generation could grow by 2.6-Bcf/d between 2010 and 2020 but only 0.6-Bcf/d between 2013 and 2020. Gas is the primary fuel that replaces coal in power generation. Increases could be strongest in 2015 and 2016 as coal plants retire, but we expect weak power demand growth and the rise of renewables to cut into the share of gas demand later in the decade.

Residential/Commercial could grow by 1.5-Bcf/d between 2010 and 2020 and 1.1-Bcf/d between 2013 and 2020, although seasonal patterns should remain volatile.

As production rises, gas demand for associated services (pipe use + lease and plant fuel) would also increase.

Exports to Mexico could increase by 4.9-Bcf/d between 2010 and 2020 to 5.8-Bcf/d, or 3.9-Bcf/d between 2013 and 2020, based on current cross-border pipeline development and demand growth in Mexico. The US exported about 1.9-Bcf/d to Mexico in 2013.

LNG exports could increase by 8.1-Bcf/d based on projects that have been approved or expected to be approved. We closely examined project timelines to arrive at this estimate.

Figure 5. US Natural Gas and Electricity Supply-Demand Balances

Annual Balances	Balance												Total		
Natural Gas (Bcf/d)	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2011-17	2011-20	2014-20
Total Supply	63.0	64.6	67.2	69.4	70.1	72.1	72.8	74.8	75.6	77.3	79.2	81.2	11.0	16.6	11.2
Prod	55.6	57.5	61.8	65.1	66.2	68.9	70.0	73.5	76.1	80.4	84.8	88.0	18.6	30.5	21.8
LNG	1.2	1.2	1.0	0.4	0.2	0.3	0.2	0.1	0.1	0.1	0.1	0.0	(1.1)	(1.1)	(0.1)
Exports to Mexico	(0.9)	(0.8)	(1.4)	(1.6)	(1.9)	(2.6)	(3.3)	(4.1)	(4.6)	(5.2)	(5.8)	(6.4)	(3.8)	(5.6)	(4.5)
Imports from Canada	7.0	6.8	5.8	5.5	5.6	5.5	6.0	6.3	6.6	7.0	7.3	7.7	(0.1)	0.9	2.1
LNG Exports	-	-	-	-	-	-	(0.1)	(1.1)	(2.7)	(5.0)	(7.2)	(8.1)	(2.7)	(8.1)	(8.1)
Total Demand	63.4	65.9	66.5	69.6	71.2	70.8	72.9	74.7	75.6	77.2	79.1	81.2	9.7	15.3	10.0
IND	17.7	18.4	18.8	19.3	20.0	20.5	21.4	22.2	23.1	23.9	24.8	25.8	4.6	7.3	5.8
ResComm	21.7	21.9	21.4	19.4	23.0	23.3	22.7	22.8	23.0	23.2	23.3	23.5	1.1	1.7	0.6
EG	18.8	20.2	20.8	25.0	22.4	20.9	22.5	23.0	22.5	22.4	22.5	22.6	2.2	2.4	0.2
Pipe Use	1.7	1.8	1.8	1.9	2.0	2.0	2.0	2.1	2.2	2.3	2.4	2.4	0.4	0.6	0.5
Lease and Plant Fuel	3.4	3.5	3.7	3.8	3.8	3.9	4.0	4.2	4.2	4.3	4.5	4.6	0.7	1.1	0.8
Transport	-	-	-	0.1	0.1	0.2	0.3	0.4	0.7	1.1	1.6	2.3	0.7	2.3	2.2
Demand + Exports	64.2	66.7	67.8	71.2	73.1	73.4	76.3	79.9	82.9	87.4	92.1	95.7	16.2	29.0	22.6
Henry Hub Price (\$/MMBtu)	4.38	4.38	4.00	2.76	3.73	4.60	4.50	4.90	4.90	5.50	5.50	5.50			
Generation (GW)	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2011-17	2011-20	2014-20
Coal	199	209	196	174	186	193	177	172	171	169	165	163	(37)	(46)	(24)
Petroleum		4	3	2	2	2	2	2	2	2	2	2	(2)	(2)	(0)
Natural Gas		103	106	130	118	107	120	123	121	121	122	123	18	20	5
Nuclear		92	90	88	88	90	94	96	98	100	101	101	6	9	12
Pump Storage		0	0	0	0	0	0	0	0	0	0	0	0	0	0
Renewables		45	56	52	55	56	57	59	60	61	62	64	15	18	9
Distributed Generation		-	-	-	-	-	0	0	0	0	0	0	0	0	0
Total Generation		453	451	447	450	448	450	452	452	453	453	452	(1)	(1)	2
Load Growth (%)		0.0%	-0.5%	-1.0%	0.8%	-0.6%	0.5%	0.4%	0.2%	0.1%	0.0%	-0.1%			
Coal plant retirement (GW) (Prorated for the year)					0.9	3.8	16.9	24.0	25.4	30.1	35.6	39.1			

Source: EIA, Citi Research

Note: Henry Hub prices from 2009 to 2014 use historical or current futures; prices from 2015 to 2020 are Citi estimates.

The following sections examine various enablers and their implications as a result of the North American natural gas revolution: (1) impacts on various sectors domestically and overseas; (2) gas supply as an enabler; (3) domestic demand's impact across industrials, electricity generation, residential/commercial and the transportation sectors; (4) global impact of US gas exports; (5) **prices – detailed derivation of the long term equilibrium given the above changes**; and (6) emissions reduction through gas substitution.

1. Impact on sectors domestically, globally

The impact of the gas revolution from both the increase in production volume and price should be broad and deep across sectors both domestically and globally. **A mid-\$5 price could be a sweet spot for many sectors.** Valuations of a number of E&P and utility companies have declined partly due to low current and forward gas prices. Higher forwards should lead to higher E&P valuation; utilities could benefit as higher gas prices push up power prices, widening profit margins (spark spreads). Industrials should remain very competitive as prices in the \$5 range is still much below the \$8 to \$10 range for Europe and \$11+ in Asia, and substantially below the \$15 gas-equivalent price of oil at \$90/bbl.

Industries benefiting from the gas revolution include those that use gas as a feedstock or energy source...

Domestically, relatively low North American gas prices should lower input costs and enhance profitability of a number of sectors. Input costs, with gas used either as a fuel or feedstock, should fall due to fuel-switching from expensive oil to gas and the migration of industries from overseas with high gas prices to the US. As discussed in an earlier section on industrial demand, petrochemicals, fertilizers, primary metals/steel-making, refineries and other energy-intensive industries should benefit.

The transport sector could see more fuel switching from expensive oil to natural gas

In addition, part of the transport sector, particularly heavy-duty trucking, rail and possibly marine transport, could switch to liquefied or compressed natural gas (LNG or CNG) as fuel away from diesel or other oil-based fuels. Industries that participate in the building of infrastructure (e.g. additional inland liquefaction facilities or gas compression devices), as well as equipment manufacturers should benefit from this fuel-switching from oil to gas.

More gas being produced at a higher price should benefit producers

Gas producers should gain from both higher expected production and higher prices. Although some have said that efficiency and productivity gains, as well as a decline of services costs, should lower the marginal costs of gas production. However, as long term gas prices should depend more on the gas prices needed to motivate non-gas-only producers to return to gas drilling, realized gas prices should be higher as a result, barring any dramatic change in both the technology and market landscape of gas production.

Electricity utilities could ironically benefit from higher gas prices because power prices would be higher too

Electric utilities could also benefit from higher gas prices because electricity prices in many regions are effectively set by gas prices, as some gas-fired power plants are still the marginal generation units. Power generators earning more on higher gas prices appear to be counter-intuitive at first. But power generators generally pass on higher operating costs to consumers; with higher gas prices, power prices would also be higher, leading to a widening of profit margins (or spark spreads). To illustrate, individual gas power plants have specific thermal conversion factors that translate gas prices to generation costs. As long as their thermal conversion factors (aka, "heat rate") are lower than the market traded value (aka, "market heat rate"), a plant makes money. This also means that margins can be larger on higher gas prices.

For example, if gas prices were \$4 and the plant-specific conversion (heat rate) were 8, the generation cost would be \$32. Assume the traded "heat rate" is 10, the traded power price would be \$40. The margin for the plant would be \$8 = \$40 - \$32. In contrast, if gas prices were \$6, then the generation cost would be \$48 (=6x8) and traded power price would be \$60 (=6x10) for a margin of \$12.

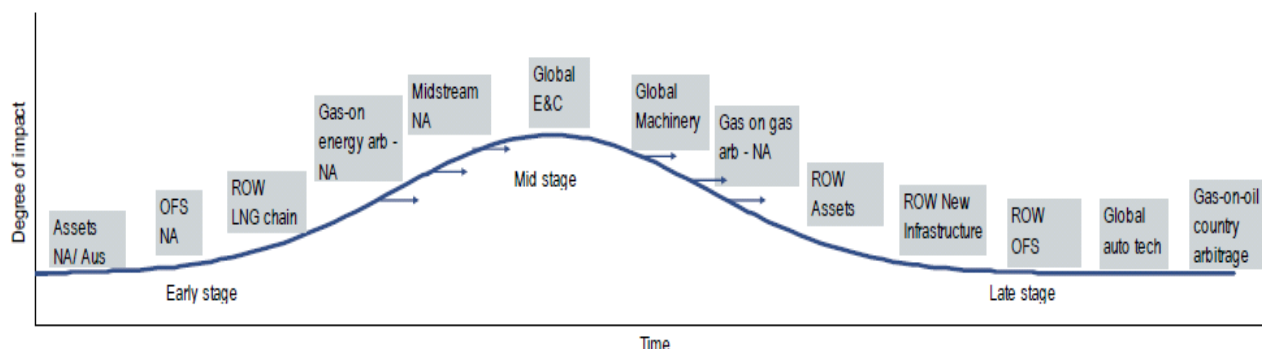
This is one of the major reasons why US utilities have been out of favor, considering how the gas forward curve has been beaten down mainly due to producer hedging, thereby dragging down long term power prices. Correspondingly, a rise in gas prices, if realized, could more than offset the stagnation in electricity demand growth.

But gas exporters competitive with US gas exports could lose out as global gas prices fall

Globally, in addition to possible industry migration from places with high fuel prices to North America, gas exporters that depend on high LNG or pipeline gas prices should see lower realized prices. As the US enters the global LNG export market, possibly providing 15 to 20% of global LNG supply based on relatively low-cost US gas, global LNG prices are expected to fall. Pipeline gas exporters could also see lower market prices as LNG prices fall. Long term contracts could be renegotiated, similar to what have happened in Europe between major utilities and gas suppliers.

By looking at net gas exports to GDP we can establish which countries would be beneficiaries of lower global gas prices. Losers from lower prices: Of the various markets where net exports of gas are a significant part of GDP it is worth highlighting Qatar, Norway, Nigeria, Malaysia and Russia as markets with a traded domestic sector. Winners from lower prices: Countries like Belarus and Ukraine as well as Turkey and some Eastern European markets have significant net gas imports. Moreover, major Asian gas importers, such as Japan, Korea, Taiwan and Mainland China, and emerging importers, such as countries in Latin America, could see their gas import cost fall more steeply.

Figure 6. The pig passing through the python: the passage of the gas revolution through global sectors, but higher gas prices should lift valuations of the E&P sector in the leftmost part of the curve



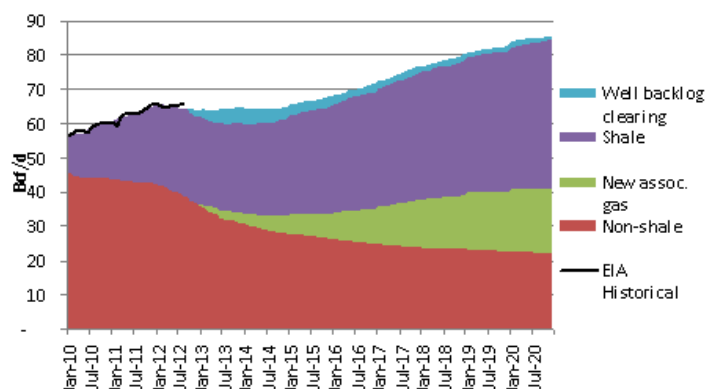
Source: Citi Research

2. Gas supply as the enabler

Supply is more than adequate due to rising reserves, technological advances, increased associated gas output and well-established pipeline network

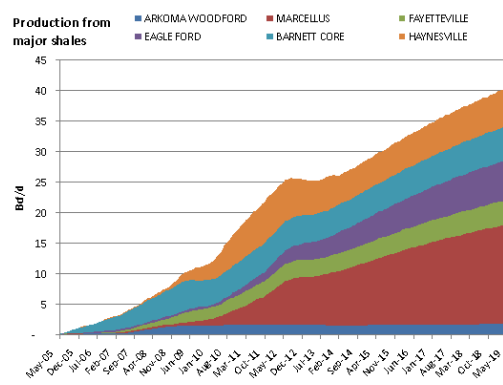
To meet growing demand and exports in the US, North America has vast gas resources to provide the necessary supply: (A) Reserve size has grown substantially and new areas are continued to be discovered; (B) technological improvements and learning-by-doing are expected to continue to boost output per well in tangible ways; (C) increased oil and liquids drilling is raising associated natural gas production; and (D) the existing well-established pipeline network between Canada and the US should allow largely land-locked Canadian gas to enter the US market as a balancer that would damp prices. In the interim, clearing the backlog of previously drilled-but-not producing wells could fill the production gap left by natural decline from late 2012 to early 2014, particularly in parts of the Marcellus and Utica region. In all, domestic US production is expected to rise by 53% to 88-Bcf/d between 2010 and 2020. To put this into perspective, this increase of 30.5-Bcf/d is about the size of the current global LNG market. Production in 2013 alone averaged 66.2-Bcf/d, or 20% of global natural gas production in 2012.

Figure 7. Projected US gas production to be driven by both shale gas and associated gas production from oil/liquids drilling



Source: EIA, Citi Research

Figure 8. Estimated shale gas production – shale gas should make up half or more of all US gas production by 2020



Source: EIA, HPDI, Company Reports, Citi Research

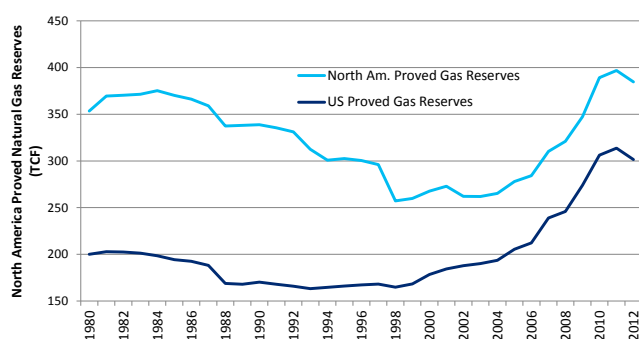
The growth of US proved gas reserves outpaced demand growth since 2005, adding significant amount of supply

A. Reserve size

The key to longer term supply stability is the vast expansion of gas reserves in North America, particularly in the US. Total US proved natural gas reserves rose 42% from 2006 to 2012, or 6.0% pa, accounting for almost 90% of reserves increase in North America. But the actual growth rate should even be higher considering the 12-Tcf drop in 2012 was due to write-downs by major producers after a very mild winter depressed prices. With the addition of 32-Tcf reported by IHS Herold, proved gas reserves appear to have increased 57% or 7.8% pa in the past 6 years instead. Total dry natural gas reserves reached 302-Tcf by the end of 2012 from about 206 in 2005.

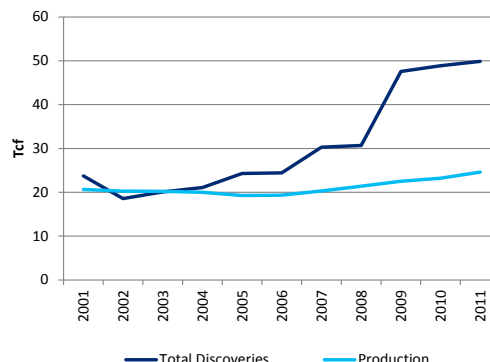
Shale Gas reserves provided much of the rise in incremental reserves, offsetting the slow depletion in other sources. Since 2008, large shale plays in the lower 48 states, including Barnett, Haynesville, Marcellus, Fayetteville, Woodford and Eagle Ford, have provided more than 90% of the addition in wet natural gas reserves, based on EIA data. If the pace of new shale reserves additions were to continue, shale reserves could account for more than 50% of the total reserves by end of 2015.

Figure 9. Growth of North America natural gas proved reserves (1980-2012)



Source: BP, Citi Research

Figure 10. Total wet natural gas discoveries have outpaced total production (2001-2011)



Source: EIA, Citi Research

The growth of new discoveries is outpacing production growth. The ratio between the new discoveries and production is close to historic high and well above 1. Note that low gas prices could worsen gas field economics. It could be a short-term headwind to the increase in reserves. But EIA estimated that total US technically recoverable wet gas reserves reached 2,431-Tcf in 2013, up from 2,203-Tcf in 2009.

B. Ongoing technological improvements should fuel further productivity gains

Ongoing technological improvements continue to raise production and recovery rates...

In addition to reserve size, ongoing technological improvements and learning-by-doing should increase production further by improving access to rocks with oil and gas, and raising recovery rates of oil and gas from those rocks. Although gas rig counts have fallen from an average of ~900 in 2011 to the mid-300 in late 2013², gas production continued to rise. Going forward, gas production may not necessarily fall even if gas rig counts were to stay at the current low level.

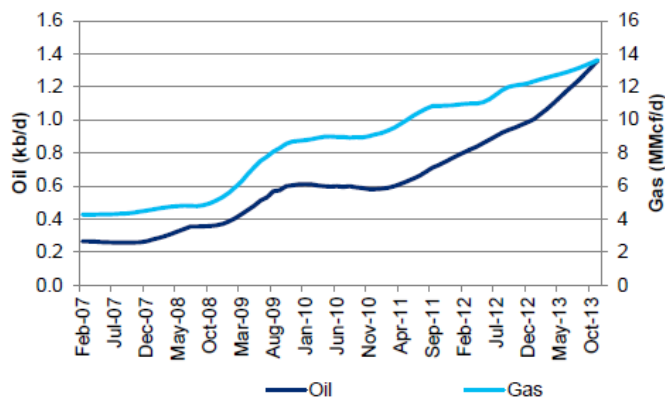
² The rig count fell dramatically because of a sharp drop in gas prices after a mild winter. This happened while producers were in the process of allocating more capital expenditure to oil and liquids exploration and development.

First, with multi-well pad drilling, where multiple wells can be drilled within a small area, the time it takes to move a drilling rig from one spot to another is reduced due to improving rig mobility. Rather than disassembling and reassembling a rig every time it is moved, a rig could be lifted and moved using hydraulic walking or skidding systems with a temporary path constructed.

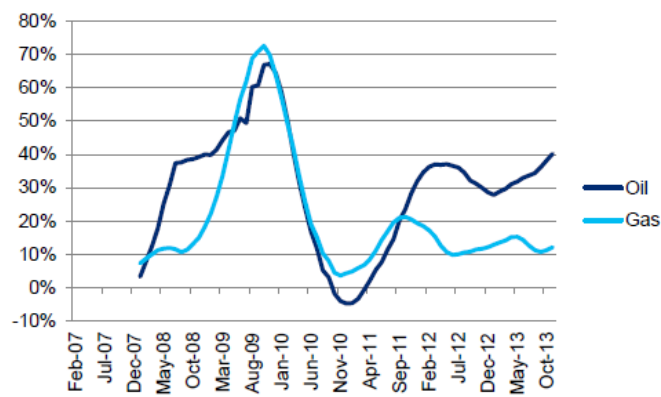
Second, technological improvements have increased the efficiency and production rates over the last few years in the modern shale drilling era, but multi-fold increases could very well be possible. Many field trials are being done that bring on incremental improvements. Technological breakthroughs often come when various technologies are used together to maximize each other's impact.

Based on the latest data collected and analyzed by the EIA, the average first month oil/liquids and gas production per rig has increased sharply. Since 2012, overall productivity gains (year-on-year change in production per rig) have hovered around 30 to 40% for oil/liquids plays and the low-10% for gas plays. There is no sign of any sharp deceleration in productivity gains yet. However, improvements are differentiated across plays, possibly underscoring the maturity of some plays and the changing focus of production. See the "[US Oil and Gas Drilling Productivity Report](#)" (Oct 23, 2013) for details at the play-level.

Figure 11. First month oil/liquids and gas production per rig (2007-2013) Figure 12. Productivity gains (y/y change in production per rig)



Source: EIA, Citi Research



Source: EIA, Citi Research

Examples of improvements include pad-drilling, better well-bore placement, improved fracturing design and use of proppants

Better well-bore placement and fracturing design have helped to keep gas production high despite low rig counts. Improvements in individual technologies and combining their uses should further boost production. The oil and gas industry is where the application of Big Data thrives as well. Here are examples of advances:

- Reduced cluster spacing, by shortening the spacing between fracturing stages leading to more perforations in the lateral of the wellbore, should boost production by creating more fractures. Some producers have reported that total production observed over the first couple of years since a well started producing has risen. Note that if the number of less effective fractures created were to increase, the flow rate could be affected.
- Geosteering allows the wellbore to better fit the shale layer, increasing the exposure of the wellbore to more oil and gas. Fracturing stages do not have to be spaced evenly.
- Increases in computing power, particularly for detailed 3-D geological modeling and analysis, have made simulation more effective. Armed with a greater understanding of how fracturing could be focused, geologists and engineers together can design better techniques and devise more suitable processes.

Continued innovation in the energy industry made the shale revolution a reality

- Proppants are critical in keeping fractures open, among other uses. An increased understanding on the use of proppants could boost recovery rates of oil and gas, with the use of different mixes of proppants. Where proppants went can be approximated by recording the sound of rock cracking, using a tracer and applying microseismic.

Dismissing the continued technological advancement in oil and gas exploration, development and production is short-sighted. Although the pace of improvement is nowhere near that of the semiconductor sector, for example, the evolution of technological change could be instructive. The principles underlying the structure of semiconductors remain largely the same as several decades ago when a number of breakthroughs were made. The famous Morse's Law asserts that the computing power would double every 18 months and this development has largely held true. What makes this happen is advancements in how silicon-based semiconductors are constructed and placed together in addition to changes in other related aspects.

Turning our attention back to shale gas and tight oil drilling, the combination of horizontal drilling and hydraulic fracturing certainly ushered in a new era in hydrocarbon development and production. But improvements are being made to each of these techniques, their synergies and other related aspects that should push the current limit even further. To say that drilling and completion techniques have reached their full potential already is akin to saying that the development of semiconductors would have stuck at where they were in the 1960s and 1970s.

Overcapacity of drilling and completion equipment could help lower production costs

Overcapacity in rigs and fracturing equipment, along with continued productivity and efficiency gains, should keep driving services costs lower, even in incremental amounts. By reducing the number of days to drill (some through pad drilling) and being more selective in fracturing, the total expenditure on drilling and completion has also been coming down, even if the day-rates have not fallen as much. Producers, in light of the competitive pressure to drive down costs amid weaker commodity prices at the producing basin level, have opted to choose more economical ways of drilling, completing and producing, rather than using the latest technology. This is akin to the 80-20 rule: applying 20% of effort with 80% of results.

See the Technical Appendix at the back for a note on decline curve analysis and how we consider the use of a more sustainable b-factor (the hyperbolic decline exponent).

C. NGL, associated gas production to remain strong even with depressed prices

Strong production growth of shale oil and natural gas liquids also boosts associated gas output, adding to supply

Gas production from oil and liquids producing wells could make up as much as ~3-Bcf/d per year of the future gas production growth. Associated gas production should remain strong as the U.S. ramps up oil and Natural Gas Liquids (NGLs)³ production – a focus of producers due to the substantial price premia over natural gas and the need to secure liquids-rich and oil acreage.

However, prices of lower value natural gas liquids could remain under pressure. Overall price levels are being dragged down by lower ethane and propane prices, due partly to inventories, but especially because of the prolific production of NGLs with constrained and inadequate demand. Exports can be difficult and costly, which explains why seaborne exports of ethane have been rare. Even if all planned

³ While there are multiple definitions of Natural Gas Liquids, NGLs are largely made up of ethane (C₂H₆), propane (C₃H₈), butane (C₄H₁₀) and pentane-plus (C₅+) but not crude oil or natural gas (i.e., methane CH₄)

petrochemical projects (e.g. ethane crackers) were to come online, it looks like there may not be enough domestic demand to absorb all of the expected ethane production.

If oil and liquids production continues to grow at a rate of 1-mb/d year-on-year, then associated gas production would rise at roughly 3.5-Bcf/d y/y, based on the distribution of oil and liquids production. However, if associated gas production were to slow down because of slower growth in oil and liquids production, then natural gas prices could be affected.

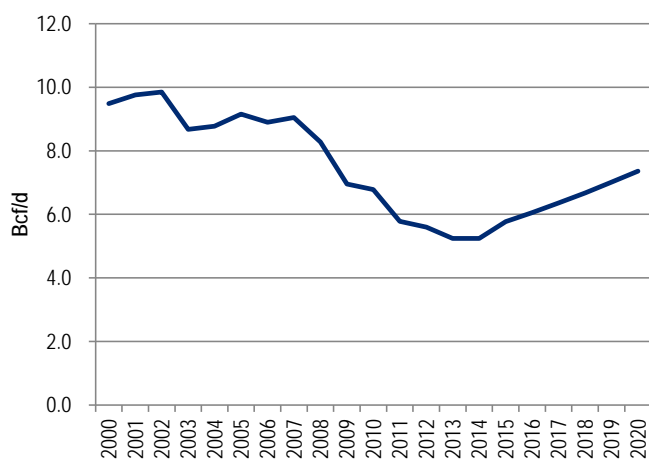
D. Canadian gas provides added supply and price buffers

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 in fact constitute a single system. Given the difficulty in establishing routes 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. A pull from the US would have a positive impact on Canadian prices, pulling them above the price range that should also make gas drilling economics work again in Alberta.

Vast existing pipe infrastructure could bring more Canadian gas from prolific shale plays there to the US

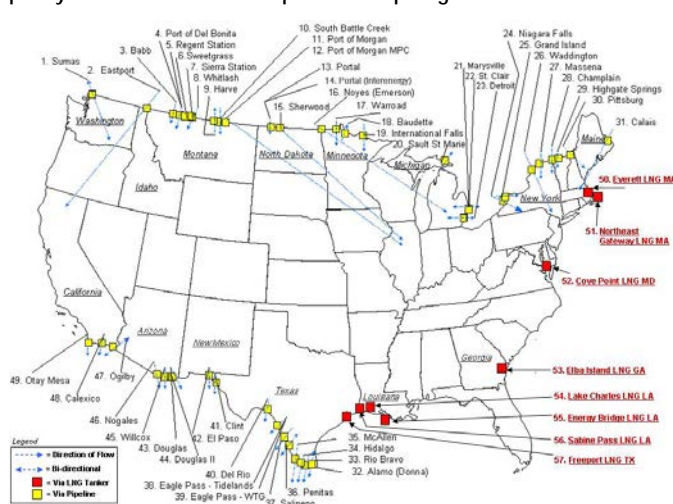
Increases in Canadian gas production and exports to the U.S. are highly feasible. Imports from Canada to the U.S. have long been supporting U.S. gas exports to Mexico. The U.S. has a history of importing a much higher amount of Canadian gas and the pipeline infrastructure can support an increase. That infrastructure once allowed as much as ~9.9-Bcf/d of net gas imports (~10.4-Bcf/d gross imports) from Canada to the US. But Canadian gas was pushed out of much of the US mid-West as pipelines were reversed to replace the Canadian gas with flows from Texas. But Canadian gas could still flow to the U.S. Midwest with the right economic incentive. Along with Marcellus gas in the Northeast part of the U.S., this Canadian gas should displace Gulf Coast gas that could be pulled into pipeline and LNG export markets.. Stranded gas in Canada without an outlet could start producing as well.

Figure 13. Gas imports from Canada (estimated values after 2013)



Source: EIA, Citi Research

Figure 14. Natural gas import and export points along the US border – plenty of infrastructure and options to import gas from Canada



Source: EIA

3. Domestic industrial, power, transportation and residential/commercial demand growth

Economic impact

The shale revolution could boost real GDP by 2 to 3.3% by the year 2020

The US economy is emerging as one of the most robust globally. Citi's "[Energy 2020: North America, the New Middle East](#)" (Mar 2012) estimated the economic impact of the North American energy revolution. The cumulative impact of new oil and gas production, reduced oil consumption and associated activity could increase real GDP by 2.0 to 3.3%, or \$370-\$624 billion (in 2005\$) respectively by 2020. \$274 billion of this comes directly from the output of new hydrocarbon production alone. The rest is generated by multiplier effects as the surge in economic activity drives higher wealth, spending, consumption, and investment effects that ripple through the economy.

Citi's economics team found evidence of how lower gas prices boosted competitiveness and increase cost advantage

Citi's economics team in the report "[Perspectives: Is a Renaissance in U.S. Manufacturing Forthcoming](#)" (May, 2013) led by Nathan Sheets looked into the state of manufacturing in the US so far. The report found that "the marked decline in U.S. natural gas prices is an additional spur to competitiveness. We find that this is providing a powerful cost advantage for manufacturing industries that are particularly dependent on natural gas... which together account for one-third of U.S. manufacturing value-added. The boost for other manufacturing industries is notable, but more moderate. We also find that those subsectors with the largest natural gas consumption relative to value-added have been relatively aggressive in their borrowing, presumably with an eye toward expanding their hiring and investment in the years ahead."

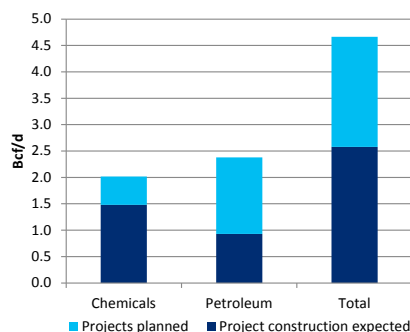
Below we examine how key sectors could benefit from the substantial increase in gas supply: (A) industrial firms; (B) power generation; (C) residential/commercial; use, and (D) transportation

A. Industrials: expansions and competitiveness enhanced

With lower gas prices, the increased use of gas as a feedstock and energy source, partly through fuel substitutions from both oil and coal to gas, could add nearly 2-Bcf/d of demand across various industrial sectors by 2015 and conservatively speaking 6-Bcf/d between 2013 and 2020. This could include retrofits or conversions adding to baseload demand. Citi's analyst Deane Dray et al examined some of these developments in "[Is There a US Manufacturing Renaissance?](#)" (Jan, 2013) Major industries benefiting from low-cost gas include petrochemicals, steel/primary metals manufacturing, agriculture/fertilizers and refining, in addition to other sectors.

For the subset of projects that we could gather based on public sources, the anticipated gas demand growth could reach 4.5-Bcf/d by late this decade and capex around US\$70 billion. The actual amount of demand and capex should far exceed these estimates, especially if small projects and expansions are included. These projects may also only account for a small portion of the expected gas demand growth due to gains in GDP and Industrial Production.⁴

Figure 15. Gas demand requirement is already rather sizeable for selected projects



Source: Company reports, Bentek, Citi Research

⁴ "Project construction expected" includes projects that have expansion ongoing, construction expected in 2014 or already underway. "Projects planned" are ones being planned, which we assume a 50% probability of project completion; gas demand and capex are probability-weighted. "Chemicals" include fertilizer plants but not all major petrochemical plants. "Petroleum" includes methanol plants.

The steel/metals sector could expand further, particularly pipe manufacturing supporting the oil/gas production boom

Steel and other primary metals manufacturing

Steel and other primary metals manufacturing also benefit from the natural gas boom. In addition to using natural gas as an energy source, gas can be used in electric arc furnace in steel-making. The midstream development and realignment have a substantial requirement for steel piping. Although oil and gas steel pipes only take up about 5% of the current market, some suggested that pipe use could make up about one-third or more of the 20% gain in the US steel market from now to 2020. Water pipes are also needed to ensure that hydraulic fracturing has sufficient access to water nearby. Manufacturing tubular steel in the US could take advantage of low energy cost, close proximity and understanding of the oil and gas markets, thereby sharply reducing imports of tubular steel products.

As manufacturing moves back to the US, indirect impacts to construction, automotive and machinery should have an effect too, though harder to quantify. In the steel sector, Direct Reduced Iron (DRI) facility uses natural gas and noncoking coal vs. a traditional blast furnace that uses coking coal. The use of natural gas injectors into blast furnaces could reduce the use of higher cost coke. Haul trucks in the sector are also seeing conversions to LNG fuel use.

Petrochemicals

The petrochem sector could expand by over 40% if all planned projects come online; many are expected to

Although the petrochemical sector mainly uses natural gas liquids as a feedstock, natural gas is also used for co-generation and as a heat source for making steam. Hence, the expansion of this sector should raise gas demand. While the new ethylene capacity is small in the context of global ethylene market, the incremental capital is likely to flow to the US, especially given that the US has a surplus of NGLs, particularly ethane, some of which is currently being rejected.

Citi's chemicals analyst PJ Juvekar forecasts North American production growth in ethylene and ammonia. For instance, if all eight major greenfield crackers were to come online, ethylene capacity could rise from 61 billion lbs in 2013 to 87 billion lbs in 2018, for a 43% growth. For the full report, please see "[Many Ways to Play US 'Shale Supremacy' – E&Cs the Next Big Thing?](#)"

Figure 16. Ethylene capacity expansions

Ethylene Capacity (mm lbs)	Location	2013	2014	2015	2016	2017	2018
Announced New Crackers							
CP Chem	Cedar Bayou, TX					3,300	
Dow	Freeport, TX					3,300	
Shell	Monaca, PA						2,500
Exxon	Baytown, TX					3,300	
Formosa	Point Comfort, TX						2,300
Sasol	Lake Charles, LA						3,300
Oxy / Mexichem	Ingleside, TX					1,200	
Axiall	Louisiana						3,000
Restarts							
Dow	Taft, LA	850					
Debottlenecks / Feedstock Conversions							
Westlake - de-bottleneck & feedstock flexibility	Lake Charles, LA	235					
Westlake - de-bottleneck	Lake Charles, LA			235			
Westlake - de-bottleneck & feedstock flexibility	Calvert City, KY		180				
Williams - expansion	Geismar, LA		600				
LyondellBasell - expansion	La Porte, TX		800				
LyondellBasell - de-bottleneck	Morris, IL	100					
LyondellBasell - expansion	Channelview, TX			250			
LyondellBasell - expansion	Corpus Christi, TX			800			
BASF/Total	Port Arthur, TX	420					
Ineos - de-bottleneck	Chocolate Bayou, TX	465					
Nova - increase utilization by 10%	Joffre, Alberta			620			
Other de-bottlenecks							
Incremental Ethylene Capacity (mm lbs)		2,070	1,580	1,905	0	11,100	11,100
US Nameplate Ethylene Capacity (mm lbs)		61,530	63,110	65,015	65,015	76,115	87,215
% of US Capacity		3.5%	2.6%	3.0%	0.0%	17.1%	14.6%
Global Nameplate Ethylene Capacity (mm lbs)		339,563	354,766	365,377	385,831	404,881	422,023
% of Global Capacity		0.6%	0.5%	0.5%	0.0%	2.9%	2.7%

Source: IHS, Citi Research

The Fertilizer industry is poised for significant growth (~50%), with plants near major agricultural areas

Fertilizers

Factors that similarly support the petrochemical expansion in the US, especially the low cost of feedstock, are also driving a resurgence in the manufacturing of nitrogen fertilizer. Planned new builds, capacity expansions and restarts could raise US capacity by 50% from 2013's level by 2017. Natural gas makes up a substantial amount (~60-80%) of the cash cost of ammonia production, where ammonia is a key ingredient of fertilizer for direct application and the feedstock for other products, such as urea, UAN, AN, etc. Several ammonia plants were closed over the past 5-10 years following elevated natural gas prices from 2005-2008. In addition, ammonia plants located in or near the major agricultural heartland of the U.S. have direct access to consumers, further boosting these plants' prospects as North America is structurally short nitrogen fertilizers like ammonia and urea. For details on planned projects, please refer to Citi Chemical analyst's report "[Fertilizers: Takeaways from TFI Conference](#)" (Nov 2013)

Figure 17. North America Nitrogen project details

North American Ammonia Capacity ('000 tonnes of NH3)								
Company	Location	Type	2012	2013	2014	2015	2016	2017
Projects - New Sites								
Agrium (cancelled)	US Cornbelt							
CHS	Jamestown, ND						750	
Farmers of N. America	Canada							
IFFCO	Quebec, Canada							750
Northern Plains Nitrogen	Grand Forks, ND							800
Ohio Valley Resources	Spencer County, IN						800	
Orascom Construction (low a Fertilizer Co)	Lee County, IA					725		
Summit Power Group	Odessa, TX						370	
US Nitrogen	Greenville, TN				60			
Midwest Fertilizer Corp	Mt. Vernon, IN							
Cronus Chemical LLC	Iowa/Illinois							
Eurochem	Louisiana							
Yara / BASF JV	US Gulf Coast							
Projects - Existing Sites								
CF Industries	Donaldsonville, LA					1,156		
CF Industries	Port Neal, IA						770	
Incitec Pivot	Waggaman, LA						800	
Mosaic (cancelled)	St James Parish, LA							
Yara (cancelled)	Belle Plaine, Canada							
LSB Industries	El Dorado, AR						341	
Invista	Victoria, TX							400
Debottlenecks / Brownfields / Restarts								
Agrium	Borger, TX	Brownfield					120	
CF Industries	Donaldsonville, LA	Debottleneck		91				
Koch Fertilizer	Various						525	
OCI Partners	Beaumont, TX	Restart	250					
Potash Corp	Geismar, LA	Restart		480				
Potash Corp	Lima, OH	Brownfield				80		
Rentech	East Dubuque, IL	Brownfield			63			
Mosaic (cancelled)	St James Parish, LA	Debottleneck						
OCI Partners	Beaumont, TX	Debottleneck			42			
Pemex	Mexico	Restart						
CVR Partners	Kansas	Debottleneck			9			
Agrium	Niskiski, AK	Restart						
Incremental Capacity Increase			250	571	174	1,961	4,476	1,950
Total North America Namplate Capacity			16,670	17,241	17,415	19,376	23,852	25,802
% of North American Capacity			1.5%	3.3%	1.0%	10.1%	18.8%	7.6%

Source: Company reports, Citi Research

Petroleum related: Refineries and methanol plants

Refineries increasingly use gas to make hydrogen and as an energy source

Refineries are major users of natural gas, nearly 4-Bcf/d, or a fifth of total industrial gas demand, according to the EIA. Using low cost natural gas as a fuel for energy can translate into substantial savings. East Coast refineries, which previously had been running at a loss, were recently bought by new owners, who touted the use of low cost Marcellus gas as a way to reduce cost.

Furthermore, although domestic petroleum product demand could be falling, particularly diesel and gasoline, the refining sector can continue to thrive. Amid restrictions on crude oil exports but unfettered exports of petroleum products, refiners can take advantage of low cost crude oil, especially if it remains partly stranded and discounted, and sell products at world price.

The methanol industry directly benefits from lower cost US gas vs. global prices; vast capacity expansion is underway

Methanol can be made from natural gas and low gas prices are fueling a building boom in methanol plants. The US is currently an importer of methanol, but with ten methanol projects either under construction or being planned, the US would become a net exporter of methanol. Together, these plants could add 1.1-Bcf/d of gas demand if all were to come online. For details on the methanol market, please refer to Citi Chemical analyst's report "[Methanol Market Update](#)" (Dec 2013)

Figure 18. North American Methanol Capacity Expansions ('000 tons)

Company	Location	2012	2013	2014	2015	2016	2017	2018
Restarts								
LyondellBasell	Channelview, TX		780					
Methanex	Geismar, LA			1,000				
Methanex	Geismar, LA					1,000		
Pampa Fuels	Pampa, TX			48	17			
Expansions								
Methanex	Medicine Hat, AB		100					
OCI Partners	Beaumont, TX	730		183				
Greenfield								
Celanese-Mitsui	Clear Lake, TX				1,300			
Lake Charles Clean Energy	Lake Charles, LA					1,000		
Southern Louisiana Methanol	St. James, LA					1,750		
Valero	St. Charles, LA					1,600		
OCI NV	Beaumont, TX					1,750		
Incremental Capacity		730	880	1,231	1,317	7,100	0	0
North American Methanol Capacity		1,885	2,765	3,996	5,313	12,413	12,413	12,413
% of capacity		39%	32%	31%	25%	57%	0%	0%
North America Demand		6,967	7,130	7,345	7,492	7,647	7,816	8,040

Source: IHS, Citi Research

B. Power generation: fuel-switching and emissions reduction

Gas-fired generation should rise by mid-decade, but weak power demand could curb further gas demand growth

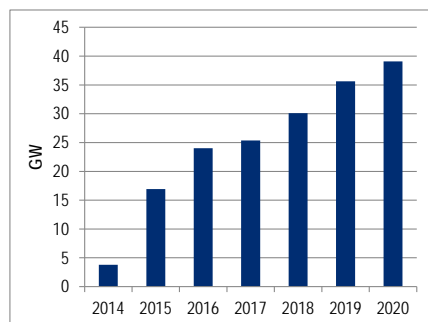
Much has been made of the potential of natural gas to substitute for coal in the power generation fleet over the next 7 to 10 years. This is based on the robust intrusion into overall fuel requirement made by natural gas in 2009-2011 based on price competitiveness. We believe this approach overstates how important natural gas will be in the future. The growth of gas demand for power generation should still be significant, despite stagnant electricity demand growth amid rising generation from renewables, but it should be less significant than is commonly believed. Multiple forces should have an impact on overall gas demand:

- (I) **Coal-fired generation retirements:** Emission rules, by inducing coal-fired generation retirements, would lead to an increase in baseload gas demand. Moreover, the persistently high cost of coal mining, compared with gas prices held down by efficiency gains in production, would continue to generate price-induced coal-to-gas switching.
- (II) **Potential nuclear reactor retirements:** Nuclear plants could retire due to the high cost of operation and maintenance, with four already taken offline in the last two years. Nuclear retirements could be a greater long-term driver of gas demand growth because of its high capacity utilization.
- (III) **Electricity demand growth:** Gas demand should benefit more from electricity demand growth than other fuels, as gas-fired power plants populate both the baseload and peaking part of the electricity

generation stack. However, power demand growth may turn out to be much slower than expected due partly to demand-side management programs.

Coal-fired generation retirement

Figure 19. Cumulative coal plant retirements



Source: Company reports, Ventyx, Citi Research

Emission rules, particularly MACT⁵, by inducing coal-fired generation retirements, would lead to an increase in baseload gas demand. By law, emission standards have to tighten starting in 2015 due to previously enacted National Ambient Air Quality Standards⁶. **Between 3- and 4-Bcf/d of additional gas demand could result**, given the 45 to 50 GW of retirements expected. Further, if carbon regulations ever come into existence, they would favor gas over coal, given that an efficient gas combined cycle plant emits less than half of the carbon as a coal plant. In addition, if coal plants older than 60 years were steadily retired, this could give gas demand a lift as well.

Further, the US Environmental Protection Agency issued a proposed rule limiting the amount of carbon emissions that all new power plants must comply with in **EPA's New Source Performance Standard (NSPS)**. The level is set at 1100 lb of CO₂/MWh, which is generally half of the amount a typical coal plant would emit and the full amount from an efficient combined cycle natural gas power plant. This new rule, if implemented, essentially mandates that power plants must use Best Available Control Technology (BACT) to control emissions, or else its construction would not be approved. Although the Obama administration stated publicly that the Administration's goal is to reduce greenhouse gas emissions, the brunt of the rule's impact would fall on new coal plants. Citi Commodities Research examined various aspects of the President's Climate Action Plan in the report ["Much Ado about Climate Change"](#) (Jun 25, 2013)

The more important ongoing development is the upcoming proposed rule by the EPA regulating existing power plants' emissions. This rule is expected to come out in mid-2014. The rule is expected to restrict the amount of GHG emissions to about half of their unrestrained emission level, or similar to the amount of emissions coming from a gas-fired combined cycle power plant. The opposition to this proposed rule could be much stronger, since it involves plants currently in operation. The commenting and draft-rule-revision periods are expected to be long, with lengthy litigation even if the final rule is implemented.

Potential nuclear reactor retirements

Longer term, the age of a nuclear unit, lackluster power demand growth and low power prices amid lower gas prices could pose challenges to nuclear operations, but potentially benefiting gas demand. Current nuclear capacity is equivalent to 20.2-Bcf/d of gas demand, assuming the use of 8 heat rate combined cycle units. Exelon, with the largest nuclear fleet in the US, canceled plans to spend \$2.3-billion on upgrades due to low power prices and demand. More stringent post-Fukushima safety measures also raised capital and operating costs. In 2013 alone four nuclear units retired: Crystal River in Florida, Kewaunee in Wisconsin and two units at the San Onofre nuclear station in Southern California. Although new plants or expansions do bring on additional capacity, such as the Vogtle plant in Georgia,

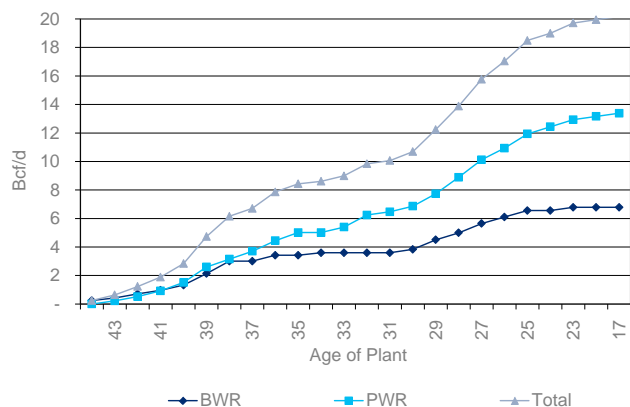
If more nuclear reactors were to retire, gas-fired generation could be the main replacement, boosting gas demand

⁵ MACT or MATS, which stands for "Maximum Achievable Control Technology" or "Mercury and Air Toxics Standards," respectively, refers to the EPA rule, with a previously expected implementation date in the middle of this decade, to "reduce emission of toxic air pollutants...from new and existing coal and oil-fired power plants."

⁶ NAAQS refers to the National Ambient Air Quality Standards. These standards were established by the Environmental Protection Agency (EPA) under the Clean Air Act (CAA).

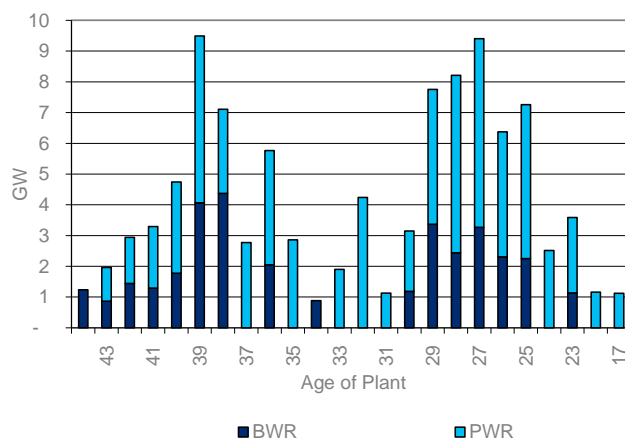
Watts Bar in Tennessee and V.C. Summer in South Carolina, nearly 14% of nuclear units are over 40 years old, representing 2.8-Bcf/d of gas demand. Both the Mid-Atlantic and Southeast have a higher concentration of older units. Any further retirements could have far-reaching impact, as outlined in a Citi Commodities Research [report](#) published on Feb 12, 2013. Citi's utility analyst published an in-depth report "[Nuclear Shutdown](#)" (Sep 18, 2013) focusing on nuclear units owned by merchant generators.

Figure 20. Cumulative gas impact based on the age of nuclear plants



Source: NRC, Citi Research

Figure 21. Size and age of nuclear plants



Source: NRC, Citi Research

Electricity demand growth

But gas demand for power generation may not grow much further after mid-decade because...

Gas demand should benefit more from electricity demand growth than other non-renewable fuels, as gas-fired power plants populate both the baseload and peaking part of the electricity generation stack. As the economy recovers, power demand should rise.

However, the overall electricity generation industry may not return to the historical growth rate of 2%pa. Long term power load growth looks likely to be limited by developments in three different areas: (1) the wider use of demand management and load response, (2) improvements in energy efficiency standards and (3) behavioral changes across sectors. (4) "Prosumers" could be large industrials or even individual households that generate energy off-grid for their own use, be it some form of distributed generation or a more sophisticated microgrid, and take away electricity demand growth from utilities.

...Demand-side management is curbing demand, especially during peak hours

(1) Load response and demand-side management can reduce peak and baseload power demand. In all of these programs, participating industrial or commercial facilities receive payment for reducing their power consumption. Alternatively, they could save money by not buying power when demand is high, when generation is scarce or when electricity prices are high. These economic incentives encourage facilities to reduce demand. Modest to negative power demand growth in industrial-heavy areas in the power market PJM in the Mid-Atlantic region of the U.S. could be signs of increased use of demand management practices.

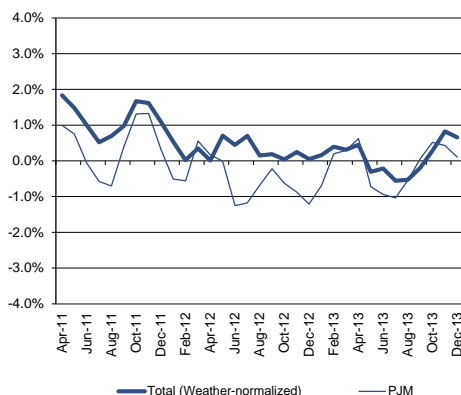
...Energy efficiency standards are also improving in many states

(2) Energy efficiency standards also in the long term reduce power demand growth. Improvements in energy efficiency are also limiting any prospect of load growth. Twenty-five states already have binding energy efficiency resource standards, which could lead to 236-TWh of energy savings by 2020, equivalent to 6.3% of 2011's US electricity sales.

...Consumer behavior may also have changed to embrace more conservation

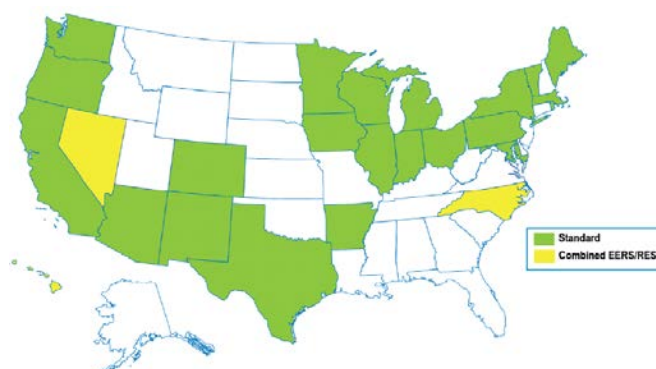
(3) Behavioral changes across sectors could be another factor in slowing power demand growth. In the residential sector, there is little to no formal ISO-level⁷ programs. But weak economic conditions and conservation, perhaps brought on by previously high energy prices and severe recession, appear to be curbing demand growth. In the commercial and industrial sectors, energy consumption is no longer a cost center, as demand reduction becomes another revenue source, turning procurement into a partial profit center. Deloitte reported in a recent study⁸ that 9 in 10 companies have goals on energy management practices.

Figure 22. Weather-normalized power demand growth has been relatively flat in North America and the key power market PJM



Source: Citi Research

Figure 23. States with Energy Efficiency Resource Standard



Source: ACEEE

Note that power demand is also a function of weather, although it is difficult to predict where the climate and weather might lead. Rising temperatures should raise summer demand for cooling but curb winter demand for heating. But if temperatures were to become more extreme, then demand should rise on net.

“Prosumers” going off-grid and generating their own electricity could further reduce demand for utility power

(4) Beyond these factors are dramatic changes impacting power generation, and among these perhaps none is more powerful than the creation of “prosumers,” or consuming entities that are producing their own electricity through wind or solar use and breaking themselves away from grids while eroding the monopoly model of power generation by utilities. We expected this factor along with other disruptive technology changes, including in storage, to limit power demand growth and hence the power sector’s appetite to increase natural gas use.

For further implications on how competing energy sources, such as renewables and shale, are bringing about disruptive changes to the energy complex, please refer to the [“Energy Darwinism”](#) GPS report (Oct 2013) for details.

On the other hand, the use of electric vehicles (EVs) could certainly increase baseload demand for power, but high costs, technological hurdles and the search for a more competitive and viable business model have slowed the penetration of EVs so far and we do not believe that there will be significant penetration of EV’s in the passenger vehicle fleet of the US in the next seven years or so.

⁷ ISOs are non-profit Independent System Operators of electricity grids that manage the dispatch of generation facilities to meet power demand, among other responsibilities.

⁸ http://www.deloitte.com/view/en_US/us/Industries/power-utilities/24fbd63d735ae310VgnVCM2000003356f70aRCRD.htm

C. Residential/commercial: fuel-switching and cost savings

Population growth, the reduction of vacancies and fuel-switching are the three major drivers of gas demand growth in the residential and commercial sectors. Demand growth could reach 23.4-Bcf/d, up 1.5-Bcf/d between 2010 and 2020.

Historically, population growth has contributed about 1% of gas demand growth in the residential and commercial sectors. However, switching from heating oil to gas for heating should be another demand growth driver that could offset the impact of efficiencies, insulation or other conservation practices. Fuel-switching benefiting gas is not confined to the power generation sector. Natural gas is gradually replacing heating oil as a heating fuel. Utilities, particularly in the Northeast, continue to introduce programs providing incentives for customers to change their boilers from heating oil-fired to natural gas-fired. Changes in the specifications of heating oil from high sulfur to low sulfur effectively turn the heating oil market into a low sulfur diesel market. This change, along with the much higher cost of heating oil vs. natural gas, motivates customers to switch over, as long as the natural gas distribution network is available.

Fuel-switching from heating oil to gas, housing sector expansion and reduction in vacancy rates to boost gas demand

A reduction in vacancy rates in both residential and commercial buildings could increase demand further. As the housing overhang is worked off, space heating and cooling needs should rise from the minimum level but even more significant has been the management of the surplus in residential/commercial space since 2007, by which utilities have been complete switched off. The minimum could be a nominal demand level that prevents damage to the structure and piping of a well-maintained building, or the minimum could be zero demand for buildings that have been off the market for so long that all heat, water and power have been shut off. The reoccupation of these vacant units would push demand back up to normal demand levels rapidly.

Further, as the housing market improves and the backlog of vacant homes and offices is worked off, the spur in construction activities would not only increase construction-related energy demand, including natural gas, but also raise the number of natural-gas consuming devices installed in new buildings. The improved availability and relatively lower cost of natural gas could shift consumer choices to gas from other fuels. This demand increase would be structural and long-lasting, as a replacement of these devices would require overcoming the cost hurdle and the "hassle" factor.

D. Transportation: gas-for-oil substitution

One of the many unforeseen ripple effects of the U.S. shale revolution is a push to substitute natural gas for oil. This is set to accelerate with LNG already challenging diesel's heavy duty truck use globally but especially in China; bunker's seaborne market and CNG are set for exponential growth not only in markets such as Brazil, Egypt, Iran and India, but in Russia and the US as well. For an in-depth coverage, Citi has completed one of the most comprehensive reports on the subject of natural gas in transportation "[Energy 2020: Trucks, Trains and Automobiles](#)" (Jun 2013).

Gas could erode oil's dominance in transportation; 25% market share in the heavy-duty trucking sector is possible

The switch from oil to natural gas in transportation is not a question of "if?" but questions of "when and how much?" Currently natural gas (compressed "CNG" and liquefied "LNG") has a low penetration rate in the domestic freight truck market, in the low single digits. However, by 2020 we expect penetration to rise to 25%, which will begin to have a noticeable impact on the cost structure of trucking. We acknowledge that certain applications, like buses and refuse trucks, are well down

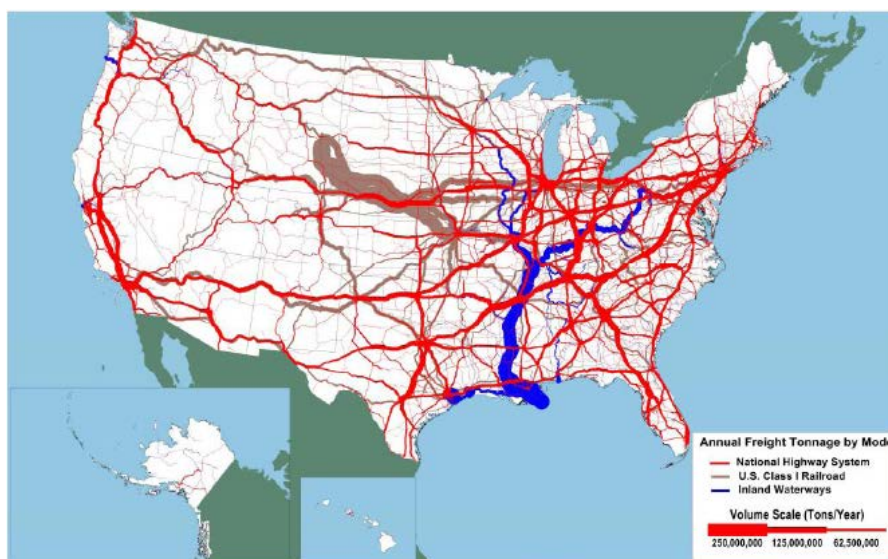
the path of adoption (for example, 80% of Waste Management's new truck purchases in 2012 were natural gas powered). There appear to be clear applications in which natural gas makes sense and adoption rates should be solid.

North America uses about 16-mb/d of oil for the transportation sector. With low natural gas prices, all but the aviation in the transportation sector provide attractive opportunities for natural gas. The potential conversion to CNG or LNG fuel is quite large. Assuming a cost differential of \$2/gallon between utilizing natural gas and diesel, the annual savings from switching amounts to nearly \$50 billion of cost savings. While utilizing natural gas as a transportation fuel presents numerous operational and financial challenges that may limit the addressable market, we believe that gas powered trucks are positioned to grow in market share for the foreseeable future.

The infrastructure needs may not be that great given focus on high tonnage, heavily traveled routes

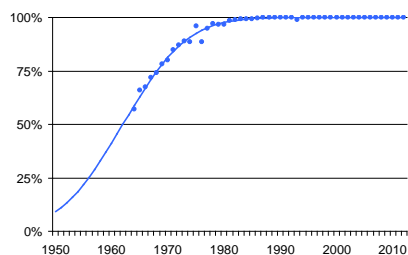
The infrastructure needed to capture a sizeable portion of the market could be smaller than commonly thought. The map below highlights the major trucking, rail and marine barge corridors, with the thickness of the corridors showing the size of the tonnage involved. There are certain key routes across the country, which dominate freight traffic and these routes should be pursued first. Major truck routes with the heaviest traffic are mostly in the Eastern half of the country along several key highways, as well as a couple of routes from West to East and along the West Coast. Hence, targeting these trucking, rail and marine routes can capture a majority of the market. Within the trucking sector, LNG could make inroads in the class 7 and 8 trucks, while CNG can also capture part of the class 3 to 7 segment but even in class 8 trucks in special shorter-haul markets. Light-duty trucks in the class 1 and 2 portion could also convert from oil to natural gas, particularly for fleet vehicles or ones that have convenient access to CNG refueling stations.

Figure 24. Tonnage on Highways, Railroads and Inland Waterways – Dominated by a Few Key Routes (2007)



Source: US Department of Transportation

Figure 25. Diesel's share of new US class 8 truck sales followed an S-curve (1950-2010)



Source: Mackay, Wards Auto, Citi Research

Strong US gas exports are expected to influence global geopolitics, upending the existing order

The adoption of natural gas as a fuel would almost certainly follow an S-curve, with the use of natural gas accelerating as more consumers switch over to the fuel. By 2025, as much as 1-mb/d of oil demand for transportation could be displaced in the U.S. The base case assumes that about 50% of new heavy-duty truck/vehicle (HDVs) sales in the U.S. would be natural gas-powered, in addition to growth of NGVs and natural gas-powered marine transport elsewhere globally.

Historical parallels in new fuel adoption

Historically, fuel substitution in the transport sector typically follows an "S" curve, which features a rapid transition period once some critical mass has been reached. A prime example of classic "S"-curve adoption is the diesel-for-gasoline substitution in the truck fleet that began in the late 1950s through to the 1970s. The market share of diesel-fueled heavy-duty trucks went from the 10% range in 1950s to more than 80% in the 1970s, taking up a majority of new sales in merely 20 years. A similar example is the transition of locomotives in rail transport. Within 20 years from 1940 to 1960, the total market share of diesel-electric locomotives rose from 5% to 95%. By the end of 1970s, most of western countries had completed the replacement of steam locomotives.

4. Global impact through gas exports

The long-held order of global gas supply and demand look likely to be upended with sharply higher US gas exports, reversing the fortunes of gas producers and consumers, and altering the existing geopolitical balance. The US should gain benefits quickly and on the cheap, helping allies while weakening strategic competitors. With lower expected oil prices and other favorable factors, Asian and global LNG prices should fall from current levels in the ~\$15 to \$18/MMBtu neighborhood to the lower-end of the \$11 to \$14/MMBtu range. European gas prices should also fall to the \$8 to 10/MMBtu range.

To what degree regional market power can be broken could determine the future of the global gas market, from breaking the supply oligopoly in Europe and monopsony in gas-rich Central Asia, to eliminating the supply oligopoly in Asia and South America. As lower global prices are increasingly evident, major gas producing companies and countries that rely on sustained high international prices could well lose bargaining power rapidly. The breaking of decades-old oligopolies could in turn increase supply and reduce prices further – a typical result of breaking monopolies or oligopolies, as producers move away from their existing high-price policy and offer higher gas volumes at lower prices.

In fact, it now seems fairly clear that North American exports could be larger than once thought, perhaps even above the initial estimate of 12-Bcf/d (92-mtpa) at the high-end and surpassing Qatar (10.3-Bcf/d or 79-mtpa) and Australia (10.8-Bcf/d or 83-mtpa) by 2020. The DOE has already approved 6.8-Bcf/d (~51-mtpa) of onshore LNG export capacity (Sabine Pass, Freeport, Lake Charles and Cove Point). With Cameron widely-expected to receive similar export authorizations, total approved export capacity could soon exceed 8-Bcf/d. Other terminals could receive the go-ahead, possibly pushing the total amount of exports to 10-Bcf/d. With potential exports from the West Coast of Canada or offshore Gulf of Mexico using FLNG (Floating LNG) if the economics work out, total North American LNG exports could easily surpass 12-Bcf/d by the end of this decade. These terminals should have high capacity utilization: Most of the US liquefaction terminals have very substantive offtake agreements from utilities or global portfolio players.

Figure 26. List of approved and pending liquefaction terminals in the US

Terminal	Company	Location	mtpa	Bcf/d
Approved (non-FTA)				
Sabine Pass	Cheniere	Cameron, LA	16.5	2.2
Freeport	Freeport/Macquarie	Freeport, TX	10.5	1.4
Lake Charles	Energy Transfer Partners	Lake Charles, LA	15.0	2.0
Cove Point	Dominion	Lusby, MD	5.8	0.8
Freeport expansion	Freeport/Macquarie	Freeport, TX	3.0	0.4
Pending				
Cameron	Sempra	Hackberry, LA	12.8	1.7
Jordan Cove	Jordan Cove	Coos Bay, OR	6.8	0.9
Oregon	LNG Dev Co.		9.4	1.3
Corpus Christi	Cheniere	Corpus Christi, TX	15.8	2.1
Lavaca Bay	Exelerate	Port Lavaca, TX	10.4	1.4
Gulf Coast	Gulf Coast LNG	Brownsville, TX	21.1	2.8
Southern LNG	Southern LNG	Savannah, GA	3.8	0.5
Gulf LNG	Gulf Coast LNG Export	Pascagoula, MS	11.3	1.5
CE FLNG	CE FLNG	Plaquemine, LA	8.0	1.1
Golden Pass	Golden Pass Products	Port Arthur, TX	19.5	2.6
South Texas LNG	Pangea LNG	Offshore, TX	8.2	1.1
Main Pass	Freeport-McMoRan	Offshore, LA	24.2	3.2
Sabine Pass	Sabine Pass Liquefaction	Cameron, LA	2.1	0.3
Sabine Pass	Sabine Pass Liquefaction	Cameron, LA	1.8	0.2

Source: Department of Energy, FERC, Citi Research

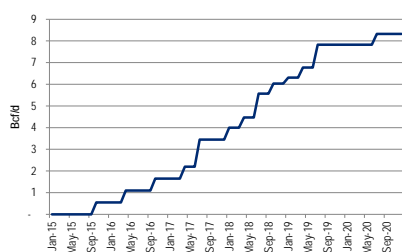
The US should see net revenue gains from net gas exports. The gas trade balance would go from -\$8Bn in 2011 to +\$14Bn in 2020 as a result of LNG exports and exports to Mexico.

Global implications

The entry of US LNG exports is timely 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 have been made 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.

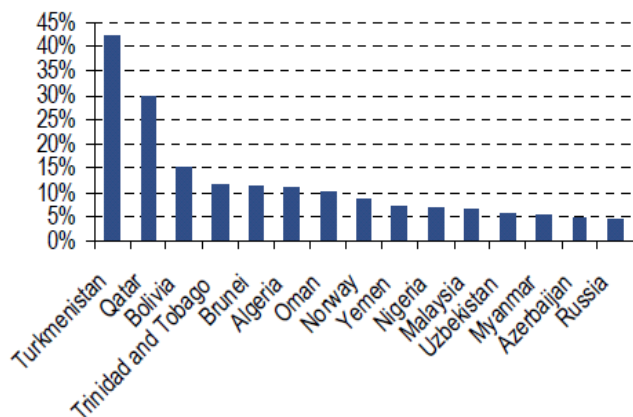
By looking at net gas exports to GDP we can establish which countries would be beneficiaries of lower global gas prices. Losers from lower prices: Of the various markets where net exports of gas are a significant part of GDP it is worth highlighting Qatar, Norway, Nigeria, Malaysia and Russia as markets with a traded domestic sector. Winners from lower prices: Countries like Belarus and Ukraine as well as Turkey and some Eastern European markets have significant net gas imports. Moreover, major Asian gas importers, such as Japan, Korea, Taiwan and Mainland China, and emerging importers, such as countries in Latin America, could see their gas import cost fall more steeply.

Figure 27. Possible amount of US LNG exports (2015-2020)



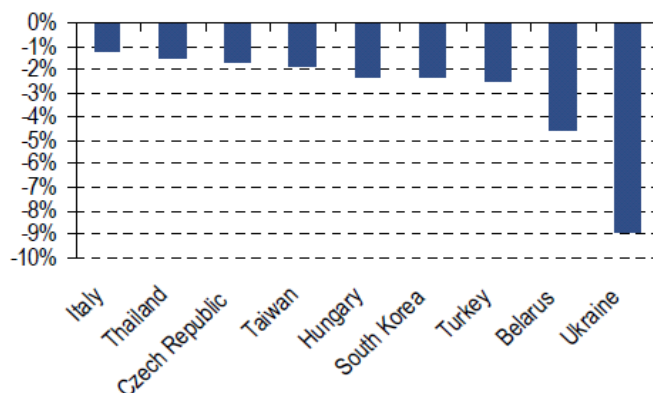
Source: DOE, Citi Research

Figure 28. Net gas exports as % of GDP: exporters



Source: BP, IMF, Citi Research

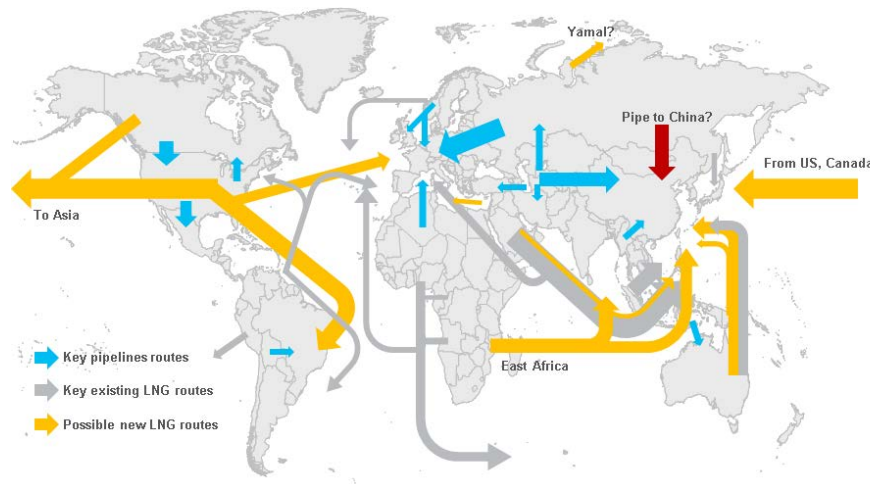
Figure 29. Net gas exports as % of GDP: importers



Source: BP, IMF, Citi Research

What's the size of the gas market? As the fastest growing major energy source, Citi expects global gas demand to rise from 310-Bcf/d in 2010 to 379-Bcf/d in 2020 for a 22% growth in 10 years, and 469-Bcf/d in 2030, for a 51% growth vs. 2010. In comparison, 89.8-mb/d of oil and liquids was consumed in 2012 vs. an equivalent of 59.2-mb/d (or 320-Bcf/d) for gas. By 2030, 469-Bcf/d of gas demand, equivalent to about 87-mb/d of oil, could come close to total petroleum demand if oil demand growth were to moderate due to high prices and efficiency.

Figure 30. Map of future global gas flow



Source: Citi Research

Note: Schematic only; size of arrows not reflective of actual flow; arrow directions indicative only

US LNG exports and the introduction of Henry Hub pricing, whose presence is already being felt globally through US coal exports, could have far-reaching impact, from (1) bringing gas-indexed pricing to the global market (instead of the current oil-indexed pricing, as if oranges should be priced using apple prices), to (2) redrawing global geopolitics. Low political risk and gas-indexation of prices appeal to importing countries looking for alternatives to oil-indexed gas and leverage for negotiation with current and future LNG suppliers. Almost all U.S. LNG export projects are brownfield developments, with lower costs and shorter construction time, significantly reducing the probability of delays or cost overruns that plagued other projects globally. With more US gas exports, [global LNG is clearly headed toward more gas-indexed pricing.](#)

US gas exports should drive growth of LNG spot market and allow importers another supply source beyond Middle East and Russia

Potential high cost liquefaction projects globally that have not gone ahead may face more headwinds in obtaining capital, signing contracts and receiving favorable contract terms. Besides the push toward gas-index pricing away from oil-linkages, the high cost of Greenfield projects clearly present greater risks in exploration, production and terminal construction, unlike U.S. or to some extent Canadian projects, which are mostly Brownfield and whose reserve sizes are more certain.

Two other factors related to North American LNG need to be taken into account in assessing impacts on global markets. First, the rise of the US as an export source will almost certainly facilitate the growth of an LNG spot market, since there will be few impediments on re-sale. The same could be true of Canadian and Australian exports. A vibrant spot market would create pricing hubs that would significantly erode oil-index pricing globally, reinforcing the erosion set off by pricing LNG exports on a Henry Hub rather than an oil-linked basis. Along with a lack of destination clauses for US LNG, these changes should lead to more trading, transactions and hedging activities, driving the growth of a global LNG spot market. **Second, buyers both in Asia and Europe already see in potential US exports as a secure source of supply** vs. exports that pass through the Strait of Hormuz in the Persian Gulf and those via pipeline from Gazprom. In short it makes a great deal of difference that much of the incremental new supply is coming from OECD countries rather than anti-markets countries like Russia and Qatar. A continued erosion of market power and geopolitics influences by existing exporters appears inevitable.

US pipeline gas exports to Mexico could surge to satisfy the country's strong demand for gas

In addition, gas exports to Mexico are set to surge as pipelines are being constructed across the US-Mexico border. Mexico has a very strong appetite for gas, with the country willing to compete against Asian countries for LNG in the ~\$15/MMBtu or above price range, even though cheap US gas is available at the border. Gas exports to Mexico could reach 5.8-Bcf/d in 2020 vs. 1.8-Bcf/d in 2013.

With the US becoming a more important supplier in the global gas market, many importers would win with the increased diversity of supply, while many exporters would lose as competition erodes their bargaining power. The potential impact of US gas exports can be seen in the regional assessments below: (A) Asia, (B) South America, and (C) Europe.

A. LNG supply surge to Asia to substantially loosen the global LNG market

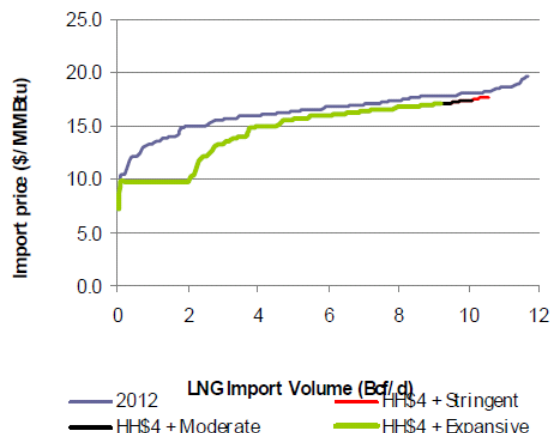
A critical market in the global natural gas trade is Asia, where strong demand growth amid the surge in LNG imports into Japan after the Fukushima accident substantially tightened the global market. Prices surge globally, leaving LNG importers globally dependent on a few nations for their gas needs.

Japan

Over the past few years, Asia's import cost curve has shifted up significantly. In the case of Japan, compared with 2010 when the average import price was \$10.8/MMBtu, the average 2012 import price has risen to about \$16.3/MMBtu. Higher oil prices have certainly driven oil-indexed prices higher, but larger gas imports to substitute for nuclear generation and the resulting tighter global LNG market pushed prices even higher. LNG imports rose from ~9.3-Bcf/d in 2010 to a high of 11.6-Bcf/d in 2012. Two major developments could help reverse the situation: US gas imports and nuclear restarts. Please refer to the report "[the Nuclear Option](#)" (Mar 27, 2013) for details.

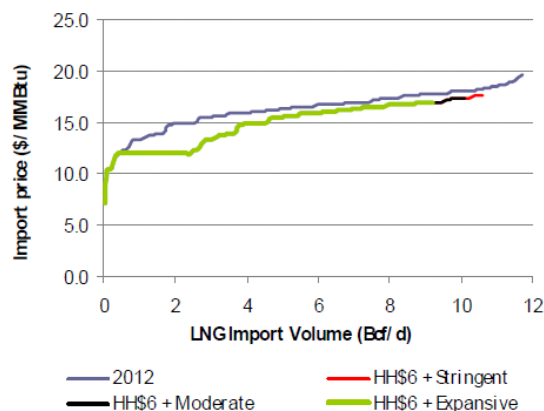
Note that US gas imports may not be able to entirely push out some long-term contracted gas, partly due to destination clauses. These clauses restrict where LNG cargoes could be headed or which party can import the cargoes.

Figure 31. Japan's gas import cost curve assuming \$4 US gas and different nuclear restart scenarios (based on 2012's curve)



Source: MOF Japan, Citi Research

Figure 32. Same as left graph but assuming \$6 Henry Hub US gas



Source: MOF Japan, Citi Research

Japan's gas import price could fall by \$1.8 to \$2.3/MMBtu with US LNG imports and partial restarts of nuclear units

In addition to imports of US gas, if nuclear reactors were to come back online, Japan's gas import prices could fall by \$1.8 to \$2.3/MMBtu. Natural gas imports displaced would be made available in the global market. Unless there is a similarly sized surge in demand elsewhere, global LNG prices should fall by a similar amount. Assuming that the market in 2016/17 will be as tight as 2012, the average import price should fall by between \$1.8 and \$2.3/MMBtu to the \$14/MMBtu range, even if Henry Hub gas were to average \$6/MMBtu. More significantly, the annual expenditure on gas imports could fall by as much as US\$24 billion, from US\$74 billion to between \$50 and \$62 billion, helping to cut the country's trade deficit.

If Japan imports even more gas from North America and East Africa, where delivered prices into Asia are expected to be in a similar or lower price range as LNG from the U.S. Gulf Coast, then Japan's average gas import price and annual expenditure should fall more. For example, if Japan imports 2-Bcf/d of gas each from the US and East Africa at a delivered cost of \$10/MMBtu, then in the more optimistic nuclear restart scenario, the average gas import price could fall by \$3.7/MMBtu from 2012's average of \$16.3/MMBtu, with annual expenditure lower by US\$30 billion to US\$45 billion, close to the US\$40 billion spent on gas imports in 2010.

More important, the tightness in the global LNG market is expected to loosen as additional LNG supply comes online in the middle of the decade, thereby reducing Japanese LNG imports and lowering global prices.

China

China was expected to be a major LNG buyer from existing exporters, but...

The surge in the construction of regasification facilities over the last few years raised hopes that China was expected to be a major LNG importer in the years ahead, boosting LNG demand and keeping the global market tight for years to come. If gas demand were to rise to 28-Bcf/d by 2020, in a scenario where domestic production remain stagnant at ~11-Bcf/d and pipeline imports fail to rise above 5-Bcf/d particularly with a lack of imports from Russia, then LNG demand

...Domestic production could continue to rise

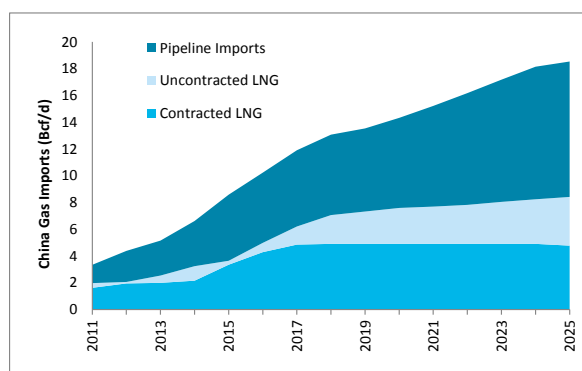
...China is buying an increasing amount of gas from and boosting investments in Central Asia

could rise to 12-Bcf/d, or more than 25% of the expected global LNG market in 2020. Although gas demand is expected to rise sharply in China based on government policy targets and the need to clean up the environment, China has not been active in signing long term LNG supply contracts. The lack of major supply deals is keeping global LNG demand forecast low, putting pressure on long term prices. Several factors are helping China's negotiating stance with LNG suppliers.

First, any sustainable production growth could lessen the need to contract for long term LNG supply: domestic Chinese production rose from a modest 2.6-Bcf/d in 2000 to 10.3-Bcf/d in 2012.

Second, China has been increasingly relying on piped gas from Central Asian countries. They are eager to look for new outlets for their gas away from the Russian monopsony,⁹ while China looks to this addition supply as leverage against LNG suppliers and Russia.

Figure 33. China natural gas imports via pipelines and LNG (2011-2025)



Source: Woodmac, Citi Research

...Slower build-out of gas delivery infrastructure and higher prices could slow gas demand growth

...Newer gas exporters as a result of many major gas discoveries globally should add to LNG supply

Third, China may not have the insatiable demand that is generally assumed by outside observers. Although the total capacity of all regas terminals is high, capable of importing a lot more LNG and with many provinces ready to increase the share of gas as part of the energy mix, the lack of infrastructure is constraining local demand growth. Managing this process of infrastructure build could slow demand growth. Further, reforms that raise gas prices (to near the level of LPG and fuel oil) should motivate more production but also limit gas demand growth.

Fourth, the surge in global gas reserves and development activities is giving hope that gas supply will rise sharply outside of major suppliers such as Russia and Qatar. Sizeable US LNG exports are critical in this formulation and so would LNG exports from East Africa and elsewhere. Russia and Qatar – the two largest gas suppliers globally – may be more eager to look for new buyers for their gas. After a surge in gas exports to Europe in 2013, the structural decline in European gas demand should lower Russia's total gas exports in the years ahead. With falling prices, Russia could be actively looking for new demand and cutting deals with buyers, especially China.

⁹ Monopsony is a market with only one buyer but many sellers, thereby giving the buyer substantial market power.

B. Gas exports to South America to pull countries closer to the US

Contrasting seasonal demand and rising gas demand for power generation in South America makes US gas attractive

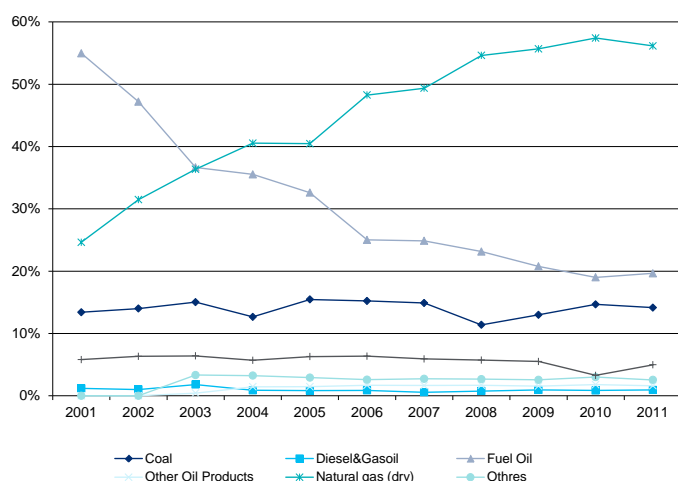
The US is likely to become a low-cost gas supplier to a region with a voracious appetite for gas. By supplying gas to South America, not only could these countries reduce their intake of expensive Pacific Basin LNG, but they could align their policies and interests more toward the US, despite a leftward, less-pro-US shift in policies in recent years. The contrasting seasonal demand makes US gas particularly attractive: winter in the Northern Hemisphere coincides with summer in the Southern Hemisphere.

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 a number of countries both encourage demand growth but hold down production gains. Argentina and Mexico, among others, have to import more LNG to satisfy demand. Developing a market price for gas remains an issue.

Mexico

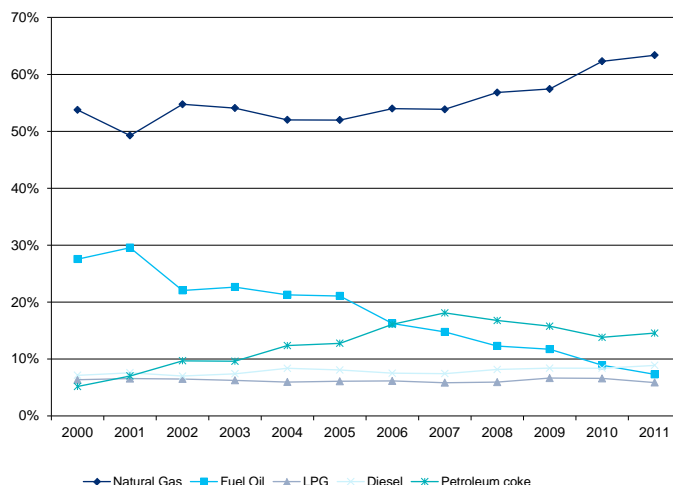
For Mexico in particular, imports of US gas could fulfill two prominent needs: power generation and industrial demand and the expansion of industrial production in energy-intensive industries. Much of the incremental demand is coming from extremely high-priced LNG, an indication of how price-insensitive the demand is. Power monopoly CFE has been buying spot cargoes at peak spot prices and signing high-priced short term deals as a result of failing to secure ample supply on longer-term contracts.

Figure 34. Fuel consumption share for electricity generation (2001-2011) – rising gas share



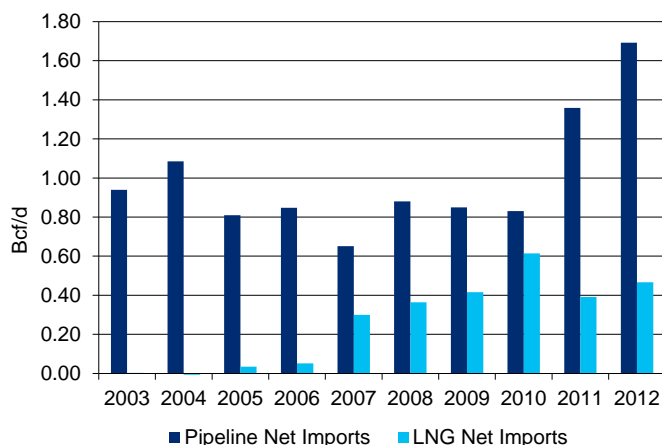
Source: SENER, Citi Research

Figure 35. Fuel consumption share in the industrial sector (2000-2011) – rising gas share



Source: SENER, Citi Research

Figure 36. Mexico's gas imports – piped gas from the US rising, but LNG imports remain sizeable despite high prices



Source: Waterborne, SENER, Citi Research

Figure 37. List of pipelines exporting gas from the US to Mexico

Pipeline Name	Expected Start Date	Capacity (MMcf/d)
Willcox Kinder Morgan Expansion	4/1/2013	185
Chihuahua-Topolobampo Pipeline	8/1/2013	1087
Mier Monterrey	4/1/2014	215
Reynosa Border Crossing	6/1/2014	300
Sasabe-Guaymas Pipeline	9/1/2014	770
Los Ramones pipeline		
Ramones Fase I	6/1/2015	1050
Ramones Fase II	12/1/2015	1050
Sasabe Pipeline	10/1/2016	510

Source: Company reports, Citi Research

US gas pipeline export capacity to Mexico is increasing rapidly to supply the insatiable demand down south

Increased imports of US gas provide a critical short-term option to tap into abundant and relatively inexpensive feedstock. To illustrate, Mexico imports LNG at Asian prices in the \$15/MMBtu range or higher even though the country also imports US gas at US prices in the \$3- to 4/MMBtu range. Thus, there is room for even more robust demand growth if supply constraints were to be eliminated, particularly inside Mexico where pipeline constraints contribute to high delivered costs in some regions. Total pipeline import capacity from the US of 2.9-bcf/d is rising rapidly to 8-bcf/d by 2016, which should be the source of feedstock to fuel future power demand and industrial growth and combined with pipelines being built in Mexico should phase out currently expensive LNG.

Over time, if the combination of Mexican production and cheap US imports creates a surplus, Mexico could reverse its LNG terminals to become an exporter, much like the US is doing now. Were Mexico to expand LNG export capacity under surplus conditions for North American natural gas production, Washington's ability to supply the Asian market increases.

Brazil and Argentina

U.S. LNG exports, as peak-shaving supply, could take advantage of contrasting seasonal demand between North and South America.

Rising generation demand in Brazil and Argentina calls for more gas imports, favoring lower cost imports from the US

Brazilian LNG demand should be increasing over time on a weather-normalized basis 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 driving 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. 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.

In Argentina, demand growth out-pacing supply turned this once gas exporter to Uruguay, Brazil and Chile, now non-existent, into an LNG importer since 2008. 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. Argentina's demand seasonality is directly opposite to that of North America, where

demand is at its highest usually from December to February. To be sure Argentina's robust shale gas resources might also be exploited and if this is the case its irrational move toward LNG imports could be reversed. Until then, Argentina has signed LNG contracts at Asian-equivalent prices of around \$15/MMBtu to attract supply in meeting the rapidly growing domestic demand.

C. US gas could break supply oligopoly in Europe and bolster allies

Europe has been dependent on 4 major suppliers - Norway, Russia, Algeria and Qatar - but US LNG could change that

Europe is largely dependent on four sources of gas, among others: Norway, Russia and Algeria for piped gas, and Qatar for LNG. But a secular decline in gas consumption is taking place in Europe due to high gas prices especially vs. the US hurting industries' competitiveness, the rise of non-gas electricity generation (e.g. renewables and coal) and the commitment to reduce energy demand. Faced with mounting losses on procuring previously contracted oil-indexed gas from traditional suppliers but selling gas at market pricing generally at a lower cost, major European utilities have been totally successful in renegotiating oil-indexed pricing with Norway and partially successful in re-negotiating with Gazprom of Russia. Lower gas demand is also eroding the market share of oil-indexed gas.

Russia's market power could fade longer term as US and other gas supplies providing more options to Europe

In this environment, Russia's long term gas supply strategy would have to change. Insisting on a high-price, oil-indexed strategy risks losing more external gas market shares and export revenues. The need to look for an outlet for rising Russian gas production, government's revenue requirements and Gazprom's own struggle in the domestic market could prompt a shift in Russia's own gas strategy.

In fact, to preserve total revenue, exporting more to Europe at more market pricing should be better for most gas suppliers than standing firm on pricing but losing market share. High gas prices would only serve to reduce demand even further as industries move to the US for its cheap gas and power generators continue to burn more coal – not a viable long term strategy for selling gas. This underlies the classic effect of breaking an oligopoly: lowering prices and raising supply.

The current surge in Russian gas going to Europe may reflect the exporter's pragmatism: regaining market share by being more flexible in pricing. Once US LNG exports enter the market, Europe would have more gas supply options, again challenging Russian gas' market dominance in Europe. European authorities have shown their concerns over Gazprom's competition practice and the lack of open access on the proposed South Stream pipeline. Gazprom has made proposals to the European Union regarding the company's pricing and other practices, while further negotiations on the South Stream pipeline are ongoing. Such regulatory issues and the steady decline in European gas demand, a critical export market for Russia, continue to present headwinds, putting increasing pressure on the country to further change its export strategy.

Global gas trading hubs

The US comes out as a winner in the development of a global gas trading hub. As LNG supply rises globally, particularly with the help of 8- to 10-Bcf/d of exports from the U.S., the increased liquidity and supply diversity should lead to an emergence of more trading hubs globally, further solidifying the role of gas-based pricing over oil-indexation. Along with a lack of destination clauses for US LNG, these changes should lead to more trading, transactions and hedging activities, driving the growth of a global LNG spot market.

Large amounts of LNG exports on the US Gulf Coast could turn the region into a regional LNG trading hub

The U.S. Gulf Coast could 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 in 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 in that regard.

Lack of destination clauses for some newer LNG contracts and uncommitted liquefaction capacity could place more cargoes into the spot market

In addition, the development of spot markets could be boosted by two elements. First, since US gas exports have no destination clause, the gas could theoretically be shipped anywhere, effectively becoming spot cargoes if the original intended destinations of these cargoes have sufficient gas supply already to meet demand. Second, since some major liquefaction projects leave a small part, perhaps ~25%, of its capacity open for spot rather than under long term contract, this gas could enter the spot market as well. (Gorgon is 65% committed and Wheatstone is 85% committed.) For gas contracts that have no destination clauses, the resale of LNG cargoes, due partly to the seasonality of demand, would add to the volume and development of a spot market.

More hybrid contracts could be structured, where LNG prices are indexed to both oil and gas prices. Gas price-indexing could go beyond Henry Hub pricing and include NBP and other European hub prices (e.g. Zeebrugge and TTF etc.) The diversion of LNG cargoes from Europe to Asia and elsewhere could make NBP prices a possible choice.

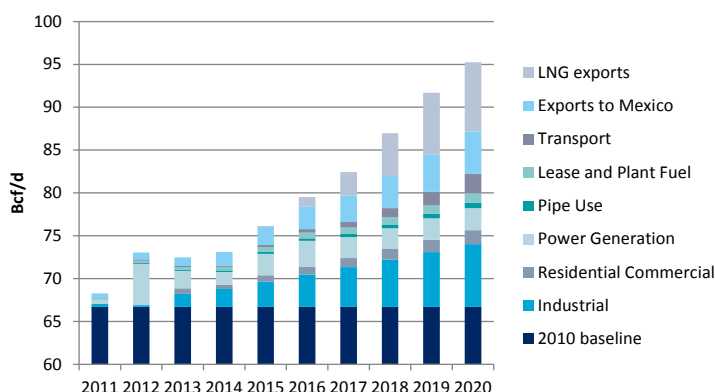
International shale gas is a promising area of development. Even though the shale revolution is yet to come in size for countries outside North America, some are already positioning themselves to follow US and prepared to start small-scale shale gas production. (1) Australia is one of the pioneers: with possibly more than 400-Tcf recoverable gas reserves estimated by EIA, the country has now attracted investments from a number of shale producers from the US and elsewhere. (2) UK is also helping its shale industry with favorable tax rate cuts and by granting more than 300 licenses for hydraulic fracturing sites. (3) China has the largest shale gas reserves and aggressive plans to develop unconventional drilling, but the technical barriers and imbalance water resources could hinder broader development. (4) Other countries that have moved forward include Argentina, Poland and Ukraine. With favorable shale gas reserves and government supports, these countries may also see commercial shale plays producing in the coming years.

All in all, substantial growth in US gas exports and consumption expected

As discussed in the sections above, despite strong production, total "demand," which consists of domestic consumption and net exports, could rise substantially for many years. "Demand" could rise by 29-Bcf/d (15.3-Bcf/d domestic + 13.7-Bcf/d exports) between 2010 and 2020. Between 2013 and 2020, "demand" could rise by 22.6-Bcf/d. More specifically, domestic gas demand could grow by 15.3-Bcf/d from 2010 to 2020. Within this, gas demand in industrial sector could grow by 7.3-Bcf/d due to fuel switching from oil or coal to gas; power generations may have 2.6-Bcf/d growth in gas usage as coal plants retires in 15/16; transport gas demand could also grow by 2.3-Bcf/d, as natural gas fueled-vehicles and vessels may rise dramatically; and residential/commercial sector may also resumes solid gas

demand growth at 1.5-Bcf/d. Besides, 13.7-Bcf/d gas demand growth may come from increasing pipeline and LNG exports. Pipeline to Mexico could add 4.9-Bcf/d demand between 2010 and 2020 based on current cross-border pipeline development and Mexico demand growth and LNG exports may need additional 8.1-Bcf/d gas according to existed and proposed LNG projects.

Figure 38. Gas demand to rise due to higher domestic consumption and exports (2011-2020)



Source: EIA, Citi Research

To put the size of “demand” growth into perspective, the gain between 2010 and 2020 is equivalent to over 90% of the current global LNG market. Such demand growth requires strong production growth to support it. But with more and more US producers focusing on oil and liquids drilling, it could take more than prices slightly higher than production cost to entice producers to drill for more gas.

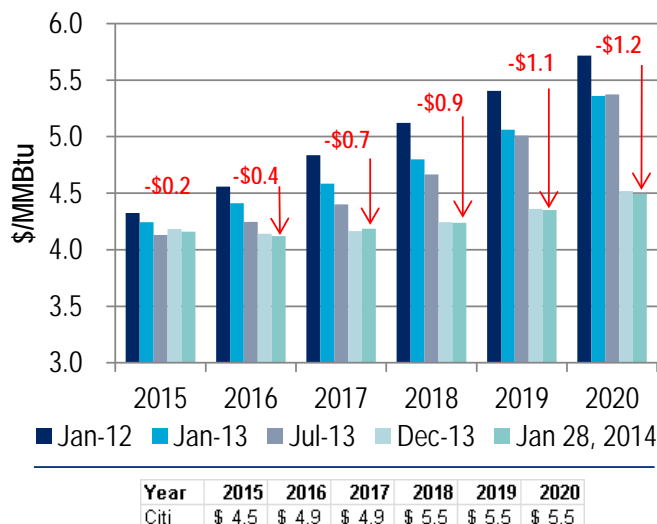
5. Prices: identifying the long term equilibrium

A surge in gas consumption and exports could put long term gas prices into the \$5 to mid-\$5/MMBtu range

With prices boosted by an expected surge in demand at home and for US exports, long term US natural gas prices could well settle in the \$5 to \$5.5/MMBtu range starting in 2018 (\$5.50 from 2018 to 2020), a level that would be above production costs at marginal gas fields. As demand and exports begin to ramp up, prices in 2016 and 2017 could rise to \$4.90 and spike higher from current levels in the \$3 to \$4 range. Prices could moderate over time as more producers switch back to gas.

Market structure, rather than marginal cost of production, could very well determine future gas prices. A common belief is that long term gas prices would fall to the marginal cost of production. This is true if gas producers have no other options but to drill for gas. Although many gas plays are supposed to be economic at \$4 or below, one critical consideration is whether shale gas-only producers have the production capacity to produce enough gas to not only replace the annual decline of existing production but also meet the need of rising demand. We do not think this would be the case.

Figure 39. The forward curve dropped sharply due to producer hedging and the resignation of some in the market that prices should fall to short term marginal costs. But market structure, switching costs, regional supply-demand imbalance should lift long term price to \$5.5/MMBtu



Source: Citi Research

Numbers denote price decline in the two years between Jan'12 and Jan'14

Productivity gains are helpful in boosting production but they are not enough to meet “demand” growth

Although productivity and efficiency improvements, along with associated gas production, should push domestic production upward, the increase in demand and exports would call for additional gas supply. This call for additional supply and the need to motivate producers to switch back from liquids drilling to gas drilling are what could drive prices higher.

As liquids production remains more profitable than dry gas, capex allocation should still go to liquids most of the time. To attract additional gas supply, gas producers who have both liquids and dry gas plays would have to see returns attractive enough to return to dry gas drilling. Gas price would have to rise to yield a sufficiently large return on gas drilling at least close to that of liquids drilling, so that more resources could be reallocated back to gas pads.

To illustrate the concept, if Brent were \$100/bbl, or \$16.7/MMBtu, then the NGL basket, which historically trades at 50% Brent, would be \$8.3/MMBtu vs. \$4 gas. With a glut of NGLs, the basket price at 35% Brent, as seen recently, would be equivalent to about \$5.8/MMBtu. Stressing the downside further, if Brent were to be \$90/bbl, or \$15/MMBtu, then an NGL basket at 35% Brent would be \$5.25/MMBtu, again vs. \$4 gas. Unless dry gas becomes competitive with liquids drilling again, the superior returns from liquids production should still draw more capital. The question is how much more costly are liquids than dry gas drilling.

Gas prices are derived by breaking down the source of the gas and gas prices needed to entice a switch away from oil/liquids

To derive prices, we calculate (1) how much new gas is needed, particularly from non-gas-only producers, and (2) gas prices required to motivate the switch from liquids to gas drilling.

(1) New Gas: With our demand forecasts, we estimated the amount of “new gas” needed by breaking down individual components of supply and production. The amount of “new gas” or “replacement production” required every year is not the total production seen in typical supply-demand balances, but it is the gas needed to offset declines in existing production and to drive production growth year-on-year.

The next step is to derive the amount of gas that has to be actively drilled. Replacement production can come from three sources: (i) gas from previously drilled-but-not producing wells that are finally coming online; (ii) associated gas from oil/liquids drilling; and (iii) gas from gas wells drilled. We estimate associated gas production and drilled-but-not producing wells based on empirical evidence and the distribution of oil/liquids/natural gas production, as previously mentioned in the section on Supply.

Figure 40. US gas production breakdown by source¹⁰

	Row	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Call on new gas production	a	57.5	61.8	65.1	66.2	68.9	70.0	73.5	76.1	80.4	84.8	88.0
Production	b	13.9	14.4	15.5	16.3	16.5	17.2	17.5	18.4	19.0	20.1	21.2
Decline of existing production	c	1.9	4.3	3.3	1.0	2.8	1.1	3.5	2.6	4.3	4.3	3.2
Production growth	d	15.8	18.7	18.8	17.3	19.3	18.3	21.0	21.0	23.3	24.4	24.4
Replacement supply	e			0.9	1.0	1.1	1.2	1.2	1.2	1.1	0.9	0.9
Oil/liquids growth (y/y; mb/d)	f			3.2	3.5	3.9	4.2	4.2	4.2	3.9	3.2	3.2
Associated gas	g			-	2.6	1.8	-	-	-	-	-	-
New well-backlog	h			15.6	11.2	13.6	14.1	16.8	16.8	19.5	21.3	21.3
Non-associated gas required	i			7.3	8.3	9.2	10.0	10.7	11.3	11.8	12.4	13.0
Production from gas-only producers	j			8.3	3.0	4.4	4.1	6.1	5.6	7.6	8.9	8.2
Production from non-gas only producers	k				13%	11%	9%	7%	5%	5%	5%	5%
Productivity gains												

Source: Citi Research

For the amount of gas coming from gas wells drilled, we separate output into two groups: gas from “gas-only” producers and “non-gas-only” producers. The latter group is the focus of the pricing discussion. Since producers in this group have both gas and oil/liquids properties, then for them to go back to gas drilling, the returns have to be high enough for them to move away from oil/liquids drilling. Using production data released by publicly traded companies, “gas-only” producers are judged to be ones that have over 70% of their own US hydrocarbon production in gas. About 47% of “new gas” production between 2011 and 2012 came from this group. The entire group had 31-Bcf/d of total production and an estimated 8.5-Bcf/d of “new gas” production in 2012.

We also incorporate productivity gains in our production forecasts. Using the latest data from the EIA on drilling productivity¹¹, productivity gains (or production per rig) rose by 13% between 2012 and 2013. Going forward, we expect a slow moderation, with a decline of about 2% in productivity gains year-on-year. We deliberately use slightly more aggressive productivity growth estimates to see how much gas could be produced.

(2) Indifference Gas Price: We conducted an extensive play-level analysis comparing the returns of drilling at major oil/liquids plays vs. major gas plays. We then derive gas prices needed for returns from drilling at shale gas plays to be equivalent to returns from drilling at oil/liquids plays, given different oil price assumptions, as seen in the following tables. For example, with \$90/bbl oil, the gas price would have to reach \$5.5/MMBtu to make the returns equivalent between drilling at a typical Bakken oil-heavy well and drilling at a generic Marcellus gas-heavy well.

¹⁰ Replacement supply (d) = (b) + (c)

Non-associated gas required (h) = (d) - (f) - (g)

Production from gas-only producers in 2012 (i) = (h) * share of total new gas production from “gas-only” producers (~47%); For (i) in 2013 and beyond, assume they could sustain productivity gain pegged at 13% in 2013 based on EIA data (k)

Production from non-gas-only producers (j) = (h) - (i)

¹¹ [“US Oil and Gas Drilling Productivity Report”](#) (Oct 23, 2013)

Indifference gas price matrices show the gas prices needed for production to switch from a liquids play to a gas play

The low-gas price environment over the last few years has forced many gas-focused producers to move more towards oil and liquids drilling. The following graph shows the concentration of companies with over 80% of its hydrocarbon production coming from gas has fallen sharply. Instead, the concentration of firms by 2012, the latest set of full-year data available, was closer to 50%.

Figure 41. Indifference gas price matrices: gas prices needed to have a similar return as a corresponding oil/liquids play based on different oil price assumptions

\$90 Oil	Haynesville	Barnett	Marcellus			\$100 Oil	Haynesville	Barnett	Marcellus
Niobrara	5.3	5.0	2.9			Niobrara	5.8	5.4	3.1
Permian	5.6	5.3	3.1			Permian	6.2	5.8	3.4
Eagle Ford	8.6	7.8	4.0			Eagle Ford	9.5	8.7	4.4
Bakken	8.2	7.7	4.5			Bakken	9.1	8.5	4.9
\$85 Oil	Haynesville	Barnett	Marcellus			\$95 Oil	Haynesville	Barnett	Marcellus
Niobrara	5.0	4.7	2.8			Niobrara	5.5	5.2	3.0
Permian	5.3	5.0	2.9			Permian	5.9	5.5	3.2
Eagle Ford	8.1	7.4	3.9			Eagle Ford	9.0	8.2	4.2
Bakken	7.8	7.3	4.3			Bakken	8.7	8.1	4.7

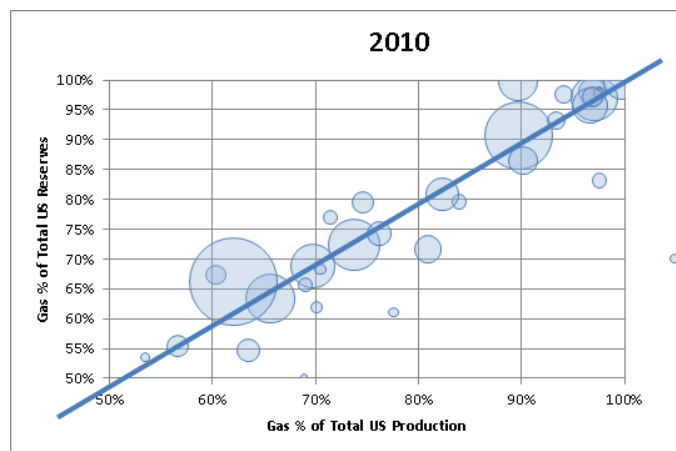
Source: Citi Research

Further, some producers have gas production forming a greater share of their total US hydrocarbon production than gas' share of their total hydrocarbon reserves. (i.e. gas production could be 70% of a producer's total oil and gas production but gas may only form 50% of that producer's total reserves.) What this means is that some producers could potentially be favoring gas production over oil/liquids by producing more gas as a share of total than its share of gas reserves would have indicated. *Hence, these producers' ability to ramp up gas production even more is questionable.* In fact, with continued higher oil and liquids prices, more of these producers could move to oil/liquids drilling in future years. Their commitment to gas drilling now may be due to the drilling carry they received from joint ventures, drilling to hold acreages and other contractual agreements.

There being many more producers focusing on oil/liquids could make it harder to boost gas production rapidly

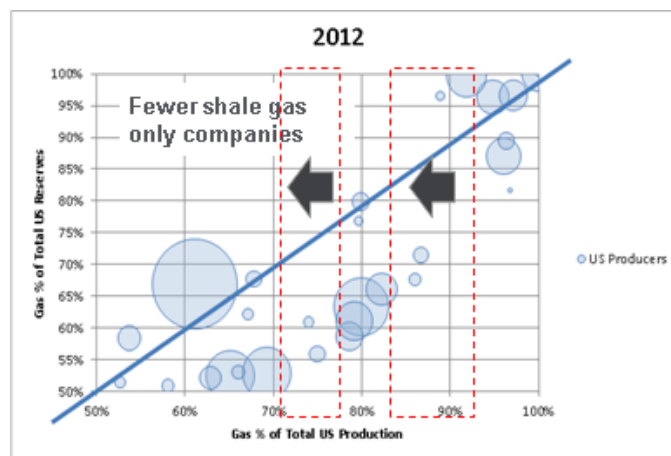
In addition, the choice of drilling for dry gas instead of these marginal liquids-rich plays may not bring in as much additional gas as one might expect. Plays that are rich in low-value NGLs tend to be ones with higher associated gas content. New associated gas production from these wells would stop if these marginal NGL plays with challenging economics are not being drilled as much as liquid plays with higher oil, butane and pentane-plus content.

Figure 42. Gas reserves as percent of total company-level oil/gas reserves vs. gas production as percent of total company-level oil-gas production (2010)



Source: Citi Research

Figure 43. Same as left but in 2012: there appears to be a marked reduction (leftward shift) in individual companies' gas production share vs. their total oil/gas production



Source: Citi Research

New entrants may see higher gas prices as a good entry point to earn high returns from gas drilling and production, but the availability of low-cost shale acreages and different cost structures between existing and new producers complicate the matter, ultimately boosting the cost of production. First, many promising shale plays have been leased and held-by-production after the frenzy in the past five years. Companies holding these locations would tend to hold on to the best plays. Second, even if new players were to enter, their “marginal cost,” which involves making the decision to buy into a play, include land acquisition and other additional overhead costs. But to existing producers with good shale acreages, these costs are sunk already. The “marginal cost” for existing producers would only consist of leasing operating expenses (LOE) and drilling/completion (D&C) costs.

Northeast basis and regional imbalances

In this context, although prices in the Northeast part of the US are gradually being weighed down by strong production from the Marcellus and Utica shales, higher fixed price at Henry Hub – the NYMEX gas price benchmark – should lift regional prices, even if there could be a \$0.5 to \$1.0/MMBtu or more price discount in the Northeast vs. the Henry Hub. A lack of pipeline takeaway capacity in alleviating the regional production glut is already physically limiting production growth. With infrastructure constraints and price discounts vs. Henry Hub prices, it is possible that shale gas production growth from the Marcellus and Utica shales may not be as strong as some of the more optimistic forecasts. Hence, higher-cost shale plays on the Gulf Coast might need to boost their gas production to meet the surge in demand there.

Although some say that backhauls or expansion of intra-states pipelines could ease the regional supply-demand imbalance, pipeline companies would probably encounter constraints that delay the process. First, they could experience rising labor cost of skilled welders, or simply a shortage of these professionals, to build or modify pipelines. Second, over time, turning compressors on existing pipelines from uni-directional to bi-directional could be insufficient in meeting future demand for gas exports out of the Northeast into the rest of the country. Third, with pipeline companies likely requiring an expansion of their pipelines, the legal process and cost involved in land acquisition could further delay and raise the expenditure of an expansion project.

Pipeline constraints could limit Marcellus/Utica production growth and keep Northeast prices low

Marginal production cost could set a soft floor on price, barring mild winters leaving too much gas in storage

Lower-bound in price to be set by the marginal cost of production

The lower-bound should be set by the all-in production cost at a marginal field, such as Haynesville. As baseload demand expands over the next few years, the long term weather-normalized price should stay at or above the marginal cost of production at the marginal play, which should be in the \$4 range. This should happen unless a mild winter causes a substantial gas inventory overhang that depresses prices to the coal-gas switching level.

Over time, as new entrants enter the exploration and production sector, it is possible that more producers would be gas-focused. The increasing share of these producers in the market could drive down prices but only over time, as companies that hold premium producing acreage should be holding on to them, divesting ones that are perceived to be less desirable. But these less desirable plays should have higher production costs as well, making them more marginal in the categorization of gas production fields.

Upper-bound in price to be set by demand slowdown, netbacks from global prices and higher gas imports from Canada

Competitive pressure sets in as prices edge closer to \$6-7, setting a soft price ceiling

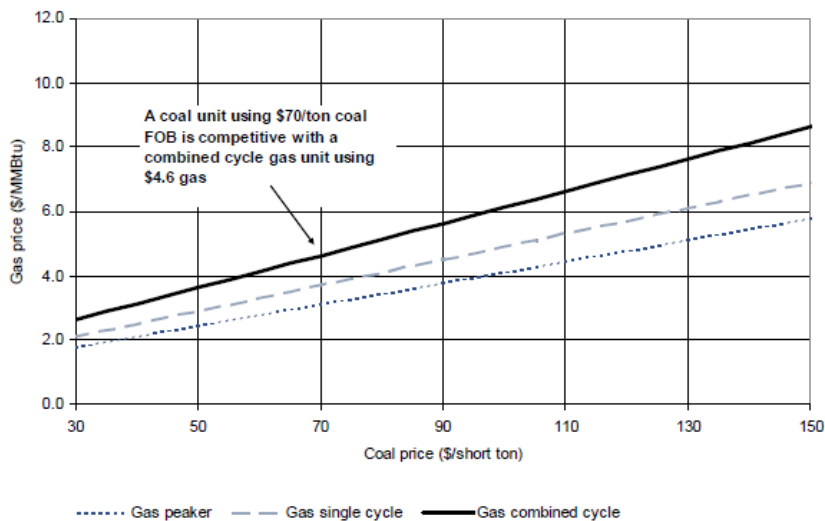
Other than the price ceiling, domestic prices should not be strongly influenced by global prices. Some have pointed to higher prices in Queensland in the Eastern market of Australia as example that high global prices would push up US prices significantly. But production there was about ~2-Bcf/d before the LNG boom. Hence, with multiple-Bcf/d of LNG, exports will become a significant part of total "demand" in the Eastern market. A number of new LNG projects will come online in the Western market but they are not connected to the Eastern market. In contrast, if the US exports 8-Bcf/d of LNG by 2020, then exports should only account for ~8% of the market in 2020 (total production plus imports = domestic demand plus exports)

A soft and temporary gas price ceiling should be set in the \$6 to 7/MMBtu range as high prices limit demand gains. At these levels, the economics of LNG exports deteriorate sharply, naturally limiting exports. Eroding cost competitiveness of gas in the transportation and power generation sectors would also reduce gas demand at that price level.

Coal-fired generation could become much more competitive vs. gas as gas prices rise, thereby limiting gas demand

Fuel competition in power generation could set one form of soft price-ceiling on gas prices. While the last few years witnessed substantial switching from coal to gas in power generation, a rise in gas price could quickly erode gas' advantage over coal. Even though coal retirements are expected to reduce the total capacity of coal plants, remaining coal plants can still ramp up their capacity utilization rates to substitute for gas plants, if coal-fired generation were more economic than gas.

Figure 44. Fuel-only breakeven costs of gas vs. coal-fired generation



Source: Citi Research

For example, at \$4.6/MMBtu gas, an efficient combined cycle gas plant would have very similar marginal costs of generation (~\$37/MWh) as a coal plant operating at \$70/ton coal. In fact, it looks as though coal prices used by power plants in the Eastern part of the US could be lower in the future, as many plants are shifting from Appalachian coal to Illinois Basin and other alternatives. Currently prompt month NYMEX Central Appalachian coal is traded at ~\$56/ton, but Illinois Basin coal, which has higher sulfur and chlorine content, among other less desirable characteristics, is assessed at \$46/ton. Assuming the \$10/ton spread were to remain in place in the future, then at \$60/ton coal, the fuel-only marginal cost of generation could be \$32/MWh. Hence, even if emission and other operating costs were to add \$15/MWh to the total operating cost, putting the emissions-adjusted generation cost at \$47/MWh, the equivalent gas price would be \$5.5/MMBtu. Therefore, higher gas prices should bring more coal-fired generation back and reducing the amount of gas-fired generation.

At high US gas prices, it becomes uneconomic to export gas to Europe, even after leaving aside capacity charges

The availability of exports to Europe could set another soft price ceiling.

Although imports of Russian gas remain critical, the gradual erosion of full oil-indexation and the inclusion of spot gas pricing and coal prices could bring European gas prices down to \$8-10/MMBtu. Recently the German Border natural gas price has fallen to the ~\$11-12/MMBtu neighborhood. For a substantial period of time over the last few years, prices have been closer to \$8 than \$10.

Our study on the long term gas demand in Europe suggests a continued downward trend toward 45.6-Bcf/d by 2015, staying in this range through 2020, down from 58.9-Bcf/d in 2010. As such, based on the current supply trajectory, if North America were to ship gas to Europe, Europe might not need to bid for expensive LNG elsewhere in the world.

If European prices were to fall to between \$8 to 10/MMBtu, given that the cost of liquefying-shipping-regasifying to Europe from the US is ~\$5, then US gas should not be competitive vs. other gas sources when US gas prices are above \$5. However, as \$3/MMBtu of the total cost is the capacity charge of using a liquefaction terminal in the US (enabling the supplier to recoup capital costs), then

the real cost of delivering gas from US to Europe could be \$2/MMBtu, with perhaps \$0.5/MMBtu as profit margin for the shipper. Netting back this \$2.5/MMBtu from Europe's long-run price of \$8 to \$10 gives a US price ceiling of \$5.5 to \$7.7.

But US LNG could also be rerouted elsewhere, particularly Asia, with South American LNG import prices in a similar range as that of Asia, due to the need to "bid" gas away from Asia to the Southern Hemisphere.

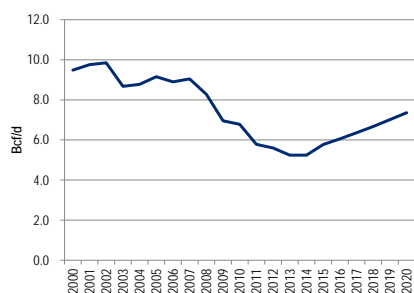
The full-netback cost, including capacity charges, of exporting US LNG to Asia could set another form of price ceiling. With long term Asian LNG prices closer to the lower-end of the \$11 to \$14/MMBtu range, netting back the ~\$6/MMBtu cost of regasification, shipping and liquefaction should mean that US prices would have to be between \$5 to \$8/MMBtu, or an average of \$6.5/MMBtu. Shippers of US LNG would effectively be losing money if US gas prices were any higher.

Higher gas prices in the US could boost gas imports from Canada, softening the price increase

U.S. gas 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 single system. Some Canadian gas produced could reach the West Coast for exports once liquefaction terminals are built, but the majority of Canadian gas can still follow the existing pipe network and reach the US. Prices above the lows in the \$2 to \$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 exports (LNG and pipelines). Stranded gas in Canada without an outlet should start producing as well.

Figure 45. Gas imports from Canada could climb from the trough as US demand rises



Source: EIA, Citi Research

Risks to our price outlook

Other than weather-related drivers, here are some of the risks to outlook:

1. If consumption and export growth were not as strong as expected, then the demand for gas production from non-gas-only producers could moderate, driving prices down closer to levels of marginal production costs. However, if gas prices are sufficiently low vs. oil and coal, then consumption will continue to be stimulated
2. In contrast, if gas consumption and export growth were much stronger than expected because many of the new "demand" sources are baseload, then prices should rise even further, but gas would quickly lose its competitive edge in sectors that are much more sensitive to gas price, limiting the size of the price surge. These sectors include power generation and spot LNG exports.
3. Gas-only producers could be much more prolific, but as our graph on individual companies' reserves and production has indicated, a number of producers might already be producing more gas as a share of total production than gas reserves as a portion of total reserves. Hence, there might be limited room for gas producers to ramp up even more

4. Lower well costs should bring down overall production costs, theoretically driving prices lower. But downward cost pressure should apply to both gas and oil/liquids wells. Therefore, decisions on capital allocation remain key.
5. Prices could skyrocket perhaps as a result of weather or other disruptive events. But high prices should curb exports substantially as global LNG prices are likely on a downward trajectory. The uptick of gas in transportation should slow as gas might no longer be an attractive alternative to diesel or other existing liquid fuels. Industrial facilities could slow their plans for expansion or fuel-switching. Gas demand for power generation could fall as gas becomes expensive while renewables generation continues to climb amid a stagnant electricity demand growth environment.

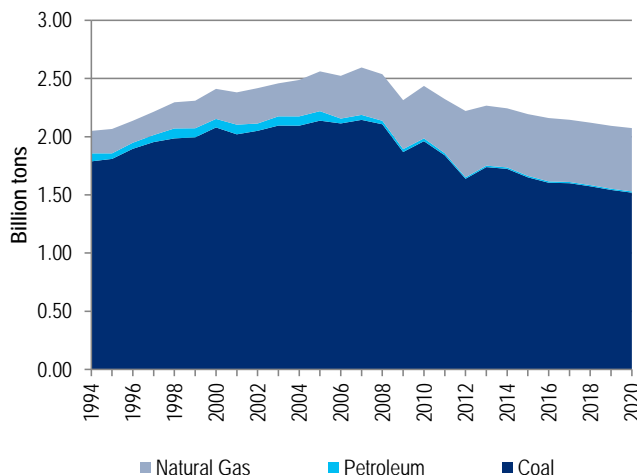
6. Emissions reduction

The increased use of gas in place of coal and oil would lower overall carbon, sulfur and nitrogen emissions

Two separate activities are generally taken into account in evaluating the impacts of emissions: greenhouse gas emitted during the process of electricity generation and fugitive emissions from the production and transport of natural gas.

In the power generation sector specifically, carbon emissions should fall further from current levels after reaching a peak in 2007, when CO₂ emissions in the sector reached 2.6-billion tons. (2005 had similar numbers.) By 2020, CO₂ emissions from power generation could fall to around 2.1-billion tons, similar to levels seen around 1995, as coal-fired power plants retire but stagnant power demand growth amid the rise of renewables also limits the growth of gas-fired generation. A 19% reduction in carbon emissions from the electricity generation from the peak should go a long way toward achieving President Obama's own pledge of a 17% economy-wide reduction between 2005 and 2020. This could happen without a carbon price or legislation in place. Economy-wide, in the EIA's annual [Energy-Related Carbon Dioxide Emissions report](#) published on Oct 21, 2013, total CO₂ emissions in 2012 fell to 5.29-billion tons, down 12% vs. a peak of 6.02-billion tons in 2007, and close to the 1994 level of 5.26-billion tons. Although a mild winter did bring down energy demand in 2012, the use of natural gas substituting coal (a.k.a. coal-to-gas switching) also reduced total emissions.

Figure 46. Estimated carbon emissions from the electricity generation sector



Source: EIA, Citi Research

Fugitive emissions are mostly methane that is emitted due to leakages at the wellhead, in the pipelines or through flaring. Capturing this gas is key, given the outsized impact of methane in a 20-year GWP scenario, though less so in a 100-year GWP scenario.

The size of methane leakage might have been reduced due to better estimation techniques. EPA's annual emissions inventory report published in April 2013 lowered its estimate of methane leakage (i.e., fugitive emissions) from the oil and gas sector. The agency pointed to tighter pollution controls contributing to an average annual decrease of 41.6 million metric tons of methane emissions from 1990 to 2010. Cumulatively, the 850 million decline was about 20% lower than the estimate published in 2012, despite a 40% increase in natural gas production since 1990.¹²

The Obama administration appears to be committed to reducing fugitive methane emissions. This reduction is a key area in the President's Climate Action Plan. Upgrading the pipeline infrastructure with government support should lower the amount of methane leakage present in some of the older pipelines. Better seals and capturing methane leaked at the wellhead during the production of gas should also be applied to limit fugitive emissions. Upcoming regulations and legislations are expected to tighten requirements in reducing methane leakage.

¹² <http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html> and <http://bigstory.ap.org/article/epa-methane-report-further-divides-fracking-camps>

Appendix

A note on decline curve analysis

Many financial analyses of shale production growth assume that the decline rate of a well would not be as steep in the out years by fitting a curve using only a short history of observed data but ignoring potential regime changes in the gas flow in the rock after the high pressure, high production period is over. Although we are not suggesting that individual shale wells' production could fall so quickly as to render them uneconomic within a few years, we do think that the production "plateau" in the long-run could be lower than what many expect. In the aggregate, a lower level of long-run production means that more new gas production would be needed. The short analysis below shows why the conventional wisdom could be misleading.

The common approach to decline curve analysis involves the application of the so-called "Darcy's Law," which describes how fluid flows in porous material and the conservation of mass. Although our analysis uses Arp's decline curve as is commonly employed in the industry, we have made adjustments to make sure our estimates conform more to the actual physics of fluid flow. Why? Due to different regimes of fluid flow shortly after a well is hydraulically fractured vs. much later in the life of a well, parameters of the decline curve equation necessarily change. Most public analyses assume parameters derived in the initial period of production to last through the life of the well. This typically lifts a well's production rate and the total amount of oil and gas extracted (ie, the Estimated Ultimate Recovery or EUR).

In more technical terms, note that a hydraulically-fractured shale well typically exhibits fractured-dominated transient flow for some years before entering the boundary-dominated flow. As Arp's equations, which generally require the hyperbolic decline exponent to be between 0 and 1 in a boundary-dominated flow environment but not in a linear transient flow environment, an exponent with a value higher than 1 is usually used in the fractured-dominated transient flow regime. But using a value higher than 1 throughout the life of a well, as is commonly applied by some in the industry, likely overstates the amount of production (i.e., EUR) in the out years. Our analysis assumes a parameter value below 1 after the initial period of production to err on the conservative side, and this is congruent with the physics of fluid flow.

A common way of mitigating this issue to set a minimum decline rate (D_{min}) of usually 5% once production decline reaches such level. Other methods are also proposed. A hyperbolic fit is changed to an exponential fit after a certain date or production level. Stretched Exponential Production Decline (SEPD) by Valko and Lee (2010) incorporates changes from non-exponential decline to exponential decline as production transition to boundary-dominated flow. Anh Duong derived a new set of equations based on empirical observations as published in 2010 in in "Rate-Decline Analysis for Fracture-Dominated Shale Reservoirs" (Paper No. SPE 137748)

Yet, if these decline curve parameters, particularly high values of hyperbolic decline exponents that underlie a number of high EUR estimates, indeed reflect the average production of a typical well, then production growth could be stronger than expected.

Best practices are important to sustaining production growth:

The increasing use of hydraulic fracturing has led to various debates on how safe the procedure is and whether the cost-benefit is worth it. Hydraulic fracturing ("fracking"), or the use of pressurized water, sand and chemicals in order to

'fracture' deep underground shale formations in order to more easily access gas and fluids, has been around for six decades. Three issues dominate discussion: (1) the adequacy of water, (2) the disposal of waste water, and (3) the integrity of aquifers. This has led to an ongoing moratorium of fracking in some states and calls for further oversight.

There should also be adequate water for fracturing with the help of recycling fracturing fluid or the use of processed brine to minimize the use of fresh water. Hydraulic fracturing uses far less water than other uses in our economy: the US Geological Survey's water use factsheet¹³ pointed out of the 410 billion gallons per day of total water withdrawals, 49% was for thermoelectric power and 31% for irrigation. In comparison, shale gas drilling may only use about 0.140 billion gallons per day, if about five million gallons of water are used per well and more than 10,000 shale oil and gas wells are drilled in a year.¹⁴ Where water is not abundant, technology is changing things, including the recycling of fracturing fluid and the use of brine instead of fresh water in some recent wells.

On the disposal of waste water, applying best practices in the storage, transport, treatment and disposal are critical, but they also do not require technological breakthroughs. Setting regulations on the treatment of waste water is key a part of the overall regulatory effort. Besides some form of recycling or reuse of this water in the injection process, water could be disposed in injection wells or into sewage treatment plants, depending on location, costs and state regulations. While some instances of water disposal into injection wells have produced microseismic activities, with a handful being felt by the public, better regulation, seismic study of injection wells and injection processes should mitigate these concerns.

On protecting the integrity of aquifers, best practices involving concrete funnels can protect aquifers when they surround the tubulars through which fracking fluids and extracted hydrocarbons flow. Proper cementing of the wellbore from the surrounding rocks is crucial.

What are other alternatives? Although other fracturing techniques, such as foam fracturing, propane and others are available, convenience and cost still seem to make hydraulic fracturing the dominant method for creating fractures in rock formations. The EPA is currently conducting a study on the impact of hydraulic fracturing on drinking water resources. A detailed report should be released in 2014.

¹³ <http://pubs.usgs.gov/fs/2009/3098/pdf/2009-3098.pdf>

¹⁴ The American Petroleum Institute reported in April, 2013, that there were 44,160 wells drilled in 2011, of which 10,173 were shale oil or gas wells. <http://www.api.org/news-and-media/news/newsitems/2013/april-2013/investment-in-us-shale-well-drilling-surges-in-2011>

Appendix A-1

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