Citi GPS

ENERGY 2020: INDEPENDENCE DAY

Global Ripple Effects of the North American Energy Revolution

Citi GPS: Global Perspectives & Solutions

February 2013

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ENERGY 2020: INDEPENDENCE DAY

Global Ripple Effects of the North American Energy Revolution

Edward L. Morse
Head of Global Commodities Research

Momentum toward North American energy independence accelerated last year well beyond the wildest dreams of any energy analyst and well above the forecast we made in our first Citi GPS report, "Energy 2020: North America, the New Middle East?."

In 2013, the US should see a stall that might last a couple of years on the natural gas side, while markets await a significant uptick in demand resulting from greenfield investments in long-haul pipeline transportation to bring natural gas to markets currently using heating oil; liquefied natural gas (LNG) liquefaction facilities to feed markets abroad; final investment decisions in energy-intensive industries like petrochemicals, fertilizers, metal fabrication and cement; an expected acceleration of retirements of coal-fired power generation plans; and a potential explosion in the use of natural gas as LNG or compressed natural gas (CNG) to displace gasoline and coal. So far the results have been stunning. In the decade through last year, power generation in the United States grew by 6%, but natural gas use as a feedstock for power generation grew by a phenomenal 47% and King Coal, whose use fell 10%, ending coal's century-long domination in the sector. Over just the last half-decade, natural gas production rose by some 14 billion cubic feet per day (Bcf/d), an increase of over 26%. Shale gas production rose during this half decade from 3.5-Bcf/d to over 26-Bcf/d, an increase in market share from 6.7% to 40% of total US production, pushing out imports of pipeline gas from Canada and LNG from around the world.

But it is in crude oil where last year saw the largest single annual increase in liquids production in US history. Crude oil production rose from the beginning to the end of 2012 by 1.16 million barrels per day (m b/d), while natural gas liquids increased by 170 thousand barrels per day (k b/d). Canadian oil production stagnated much of last year due to project delays but both output and exports to the US grew by some 300-k b/d in 4Q'12 and are expected to grow by another 300-k b/d this year.

The robust growth in North American production over the last two years helped to keep a lid on oil prices globally as the level of supply disruptions from both OPEC and non-OPEC producers rose from their historical background level of 400- to 500-k b/d to an average of above 2-m b/d since early 2011. Starting this year, North American output, as we indicate in this report, should start to have tangible impacts both on global prices and trading patterns, and will eventually turn the global geopolitics of energy on its head.

Since 2006, US field production of crude oil, plus output of natural gas liquids and biofuels has increased by close to 3-m b/d—about the same as the total output of Iran or Iraq or Kuwait and more than that of Venezuela. Meanwhile, Canadian production has grown over this same half decade by 510-k b/d, with the rate of growth accelerating above the 100-k b/d increase over the past five years to over 175-k b/d annualized even as US production has accelerated. As a result of declining US consumption of oil products and rising production, US net oil imports have fallen by over 6.5-m b/d, from a peak of 13.4-m b/d in late 2006 to under 6.7-m b/d in late 2012. US production of oil and natural gas liquids is accelerating and is now running at over 1-m b/d of growth annually.

The impact of this extraordinary production growth is becoming increasingly apparent and even if the growth rate subsides in the years ahead, the mushrooming effects of this growth will have dramatic impacts. A half-decade from now, combined US and Canadian oil output could be in surplus of projected needs. And over the next five years, demand for natural gas in the US should catch up with supply, opening up unexpected opportunities in transportation and igniting a re-industrialization of the country.

Oil prices look likely to fluctuate in a range significantly below the $90-120 per barrel range in which Brent has traded since 2011 toward $70-90 by the end of this decade. Because of changing dynamics in the geographic spread of production of unconventional, as well as conventional supplies (notably from Iraq), and because of growing inroads that natural gas should have in displacing oil products in the transportation sector, OPEC should find it challenging to survive another 60 years, let alone another decade. The United States should see its role in the world as a singular superpower enhanced and prolonged. But not all of the consequences are positive, for when it comes to the geopolitics of energy, the likely outcomes are asymmetric, with clear-cut winners and losers.

The probability of North American energy independence is extremely high, and even the prospects of energy independence for the US alone are real. This does not mean that the US automatically becomes isolationist or that defense expenditures necessarily become more questionable. But it does provide unexpected opportunities for the country's foreign and trade policy. Will the US continue to provide security guarantees for its longstanding allies and sources of supply? Will China step in to buy supplies where the US no longer needs them, strengthening relations with new partners in the process? These changes will evolve over a period of years, not months, but the shifts are likely to be significant, with profound long-term implications.

Burgeoning US energy independence brings with it an opportunity to re-define the parameters of post-Cold War foreign policy. Can an increasingly polarized and domestically-focused US political class take advantage of the opportunity to re-formulate the country's relationships, long-influenced by the need for secure and reliable access to energy supplies, accordingly?

Some producer countries should find their dominance challenged as a result, and those suffering most acutely from the resource curse may see their leadership come under heightened pressure for economic and political reform, as revenues gradually diminish, raising the risk of creating new failed states in the process. Declining revenues in former authoritarian petrostates could prompt middle classes and political elites to switch allegiances from current leaders, resulting in power struggles or upheaval. Importing countries may seek new terms of engagement with new suppliers, re-drawing the map of the international system in the process.

The implications for the global petroleum sector – for trade, for shipping, for the relationships among crude oil streams – are profound, as are the implications for oil prices, which will be weighed down significantly by the change in the position of the United States. Perhaps the most significant changes in store befall the geopolitics of oil and natural gas, where there is a long list of winners and losers, and where win-win solutions for producing and consuming countries might well prove to be elusive, and where the bitter politics of adjustment could be another complicating element of the global geopolitical landscape.

These ripple effects of North American Energy Independence are the subject of this report, which is both an update and a companion to the Citi GPS Report, "Energy 2020: North America, the New Middle East?", published in March 2012.

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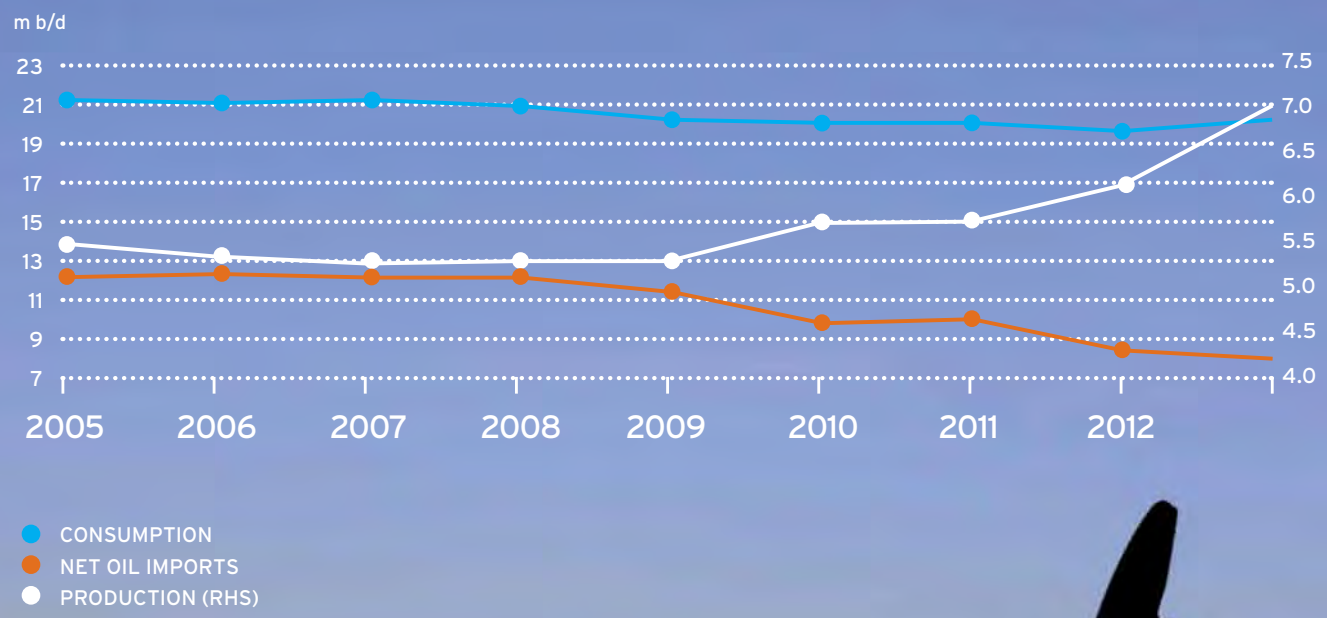
Crude production has surged while demand is in structural decline, leading net imports to fall substantially



By summer of 2013, the US will no longer need to import light sweet crude into the US Gulf Coast.

Canada will be the primary supplier of sour crude into the US Gulf Coast by end 2014.

Export of crude oil from the US Gulf Coast could be seen by end of the decade.

Energy 2020: Macro Analysis

Snowballing Impacts of the North American Energy Supply Revolution

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The US and Canada have been outliers in their rapid supply growth, so far, but Iraq — and other global supply growth — is set to join this "dynamic duo"

The energy supply revolution unfolding in North America is both breathtaking and extremely local, at least to date. For the past four years the United States and Canada have, combined, led the world in growing their production of crude oil and natural gas liquids. And year-to-date combined production from the two countries has kicked up several notches, with a run rate for the dynamic duo of well over 1-million barrels a day (m b/d). That's more than the anticipated global oil demand growth for last year and this year. One OPEC country, mired in political controversy, is raising its head, as if to say, wait a second, we may be second best, but we have untapped oil resources that are a great deal bigger than those of North America and we have room to grow as well: that country is of course Iraq, which last year increased its output by over 500,000 barrels per day (500-k b/d). It looks as though Iraq might just be able to keep up the flow rate and at times jump above the current run rate of adding as much as 600-k b/d per year to production for years to come.

But it's the North American supply record that is the focus of global attention, with doubts about whether this splashy supply growth is meaningful or sustainable, even after four years of accelerating performance. Since the publication of Citi's report, "*Energy 2020: North America, the New Middle East*?", published in spring 2012, both the Canadian and the United States' production bases have spurted up at an even higher rate than forecast. Meanwhile, the US has instituted new automotive efficiency standards that could well reduce US oil product consumption by 2-m b/d rather than the 1-m b/d published in that report, accelerating the time when energy self-sufficiency, or "independence", becomes the rule of the day.

Not only is North American oil supply growth noteworthy, but consumption is falling too, due to fuel efficiency, demographics, and importantly, oil-to-gas substitution

On top of this, the expected persistence of the gap between oil and natural gas prices should see an acceleration of substitution, especially in transportation, and initially affecting the diesel fuel market. The conversion of the US heavy-duty truck fleet to natural gas-based LNG, or liquefied natural gas, may reduce oil product consumption even more than we had contemplated last year. At that time Citi Research postulated that, by 2015, perhaps 10% of heavy duty truck usage (a total of some 2-m b/d) could be converted to natural gas, removing 200-k b/d of diesel demand and increasing natural gas use by 1.2 billion cubic feet per day (Bcf/d). It appears as though our estimates might have been too conservative and our current assessment is that a minimum of 30% of the fleet might convert to natural gas by 2015, removing 600-k b/d of diesel demand from the economy and substituting it with 3.6-Bcf/d of natural gas use. Meanwhile, the 600-k b/d heating oil market in the US Northeast looks likely to also collapse, with natural gas pipelines from Pennsylvania's natural gas-rich Marcellus shale bringing new natural gas supply to New York City and potentially to New England. Where pipeline construction is challenged, abundant and cheaper propane from Pennsylvania and Ohio look to be plausible challengers to the diminishing heating oil market, especially as that market is moving toward becoming an ultra low sulfur distillate (ULSD) market, or effectively an expensive ultra low sulfur *diesel* market. As for substitution by renewables and their capacity to replace hydrocarbons, these could be critically important in the next decade; for now, they need to grow to a more meaningful percentage of primary energy consumption before having an impact.

Thus, the US is moving rapidly toward self-sufficiency, which is transformative for markets as well as global geopolitics

A move over the course of the decade in which the United States is transformed from the largest hydrocarbon producer and importer in the world to self-sufficiency, or close to it, and in which North America becomes an exporter is big news and transformational. And yet, there remain major doubts as to whether the consequences of this transformation are meaningful.

Mexico, too, could surprise with production growth after languishing recently

The original *Citi GPS: Energy 2020* report also speculated that surging Mexican production ought not to be discounted. We are now prepared to make the judgment that Mexican production is likely to surprise significantly to the upside during the remaining eight years of this decade and certainly, should we want to look at a ten-year horizon through 2022, even more so. Since Mexico's Presidential election in July 2012, Pemex has announced two natural gas and two oil discoveries in the deep waters of the Perdido Fold Belt on the Mexican side of areas that correspond to areas in the United States which are currently massive producers of oil and natural gas. It has also managed to increase onshore production at a rapid rate, and appears on its way to have overcome declines in its giant offshore Cantarell field with enough production so as to be on the verge of a new period of potentially persistent production increases, enabling Mexico to join Canada and the US in their production renaissance. At the time of writing, the newly elected Mexican government appears to also be making significant progress in building a national consensus allowing more rapid development of Mexico's onshore shale oil and gas resources as well.

While the implications of the North American supply revolution are mostly positive, there are some potential risks – there are losers, not just winners

This report outlines some of the most significant international implications of the unfolding revolution in natural gas and petroleum supply in North America. Many of these are positive, especially for the countries of North America, but the positive consequences are not evenly spread. What's more, when it comes to the geopolitics of oil, there are losers as well as winners, and that's because it appears likely that this supply resurgence will spread well beyond North America shores by the end of this decade and weigh heavily on prices, challenging a wide swathe of countries whose income from oil and natural gas exports should undergo severe challenges.

Self-sufficiency also has consequences for the international pecking order of power. No other country is likely to be as advantaged as the US when it comes to the requisites of superpower status. The US, by the end of this decade, looks likely to have shed two of the major weaknesses it has confronted as the world's leading global power. It could be freed from the shackles involved in sacrificing a values-driven policy focusing on human rights and democratic institutions in order to secure cooperation from resource-rich despotic regimes. (Whether it takes advantage of this opportunity is a separate point—foreign policy driven by interests rather than values could well continue to dominate.) Sharply reduced imports of oil along with the growth of competitive industries in energy-intensive areas — based on perhaps the cheapest natural gas feedstock available anywhere in the world except Qatar — should have similar current account impacts when it comes to petrochemicals, fertilizers, steel manufacture, other metal fabrication, cement and glass. Protecting the dollar should no longer be an Achilles heel of superpower status as the dollar should likely reign stronger. These new attributes are not so readily available to resource-dependent China while lower-priced oil, natural gas and probably other commodities should severely impact Russian earnings and foreign policy freedom.

To be sure, new-found energy self-sufficiency will not make the US economy immune to oil disruptions — in a global economy prices are set in a global market place and autonomy in crude oil and natural gas does not shield an economy from price impacts that are international in nature. Nor does self-sufficiency support an isolationist posture – for the United States, effective borders are the globe as a whole, and the defense of trade routes and shipping lanes, protection against terrorist attacks, against cyber warfare and biological and chemical warfare and

making sure the world is a safe place for the pursuit of the longstanding US priorities of democracy, free trade and open markets should remain key priorities for the foreseeable future. However, a surplus export capacity is in fact a protective force and is akin to having spare production capacity, since exports can be reduced by government policy in the eventuality of a global supply disruption as a means of insulating the economy from some of the more severe impacts of higher prices.

Those oil producers depending on US import demand for light sweet crude should see these markets dwindle – West Africa is most affected by this trend

Long before this supply miracle impacts the international security sector it should have potentially transformational effects on the structure of the global petroleum and natural gas sectors. Already this effect has been seen on countries that used to count on the US market for sales of light sweet crude – the countries of West Africa and the Mediterranean, which benefited from the once growing US appetite for imports. By this coming summer, the US should no longer need to import light sweet crude into the US Gulf Coast, while refiners on the US East Coast should be able to replace some of their imports with substitutes produced in the US midcontinent, and brought to Albany, NY, New Jersey, Pennsylvania and Virginia by rail, and the premia received by West African producers, already challenged, could be lost.

Already pressure is growing to move light sweet crude from the US Gulf Coast to higher value locations. With exports for all practical purposes currently banned in the US except from Alaska or to Canada, in a few months' time, flows in increasing quantity at increasing frequency should move light sweet crude from the US Gulf Coast to eastern Canada, rapidly removing the need over the next two years more for light sweet crude exports from Africa and the North Sea to Canada. Within two years, pressure should build for exports to other destinations, for pipelines to the East Coast and/or pressures on the US cabotage laws (the Jones Act) that currently restrict inter-coastal trade to expensive US-flagged vessels. One likely development is pressure to allow the licensing of exports to Korea, which is a Free Trade Agreement (FTA) partner of the US where tariff-free imports from the US, like current tariff-free imports to Canada, make a compelling economic case. Meanwhile rail-transported crude oil should also grow considerably, as it provides a less expensive transportation mechanism in some cases than Jones Act carriers.

But heavier, sourer crudes will also see their markets challenged as pipeline build-out allows Canadian oil sands to reach the US Gulf Coast market, pushing out Middle East, Venezuelan and Mexican crudes

By the end of 2014, just two years from now, sour Canadian crude should make its way via new pipelines to the US Gulf Coast in increasing abundance, while a surplus of sour and heavier crude from Canada should move from the US midcontinent to the US Gulf Coast. When that happens, the main suppliers of imported crudes into these markets will join today's West African producers in seeing their markets challenged. These exporters include Saudi Arabia, Iraq, and Kuwait in the Middle East. They also include nearby Venezuela and Mexico, whose exports are likely to be pushed out by competitive Canadian suppliers, favorably linked to the US Gulf Coast market by pipeline. Or, they may have to discount their crudes to preserve market share in the US.

By the middle of this decade Canadian and US-produced light sweet crude should be delivered in growing quantities to the US East Coast and Gulf Coast. At the same time, North America should be supersaturated with crude and the US should require less crude to satisfy its dwindling needs as consumption shrinks, and Canadian crude surpluses continue to grow. Even before two Canadian pipeline expansions to the Pacific are completed, there could begin to be exports of crude from the US Gulf Coast – Canadian crude most likely, and potentially US crude if the US succumbs to economic logic, and lifts the current multiple bans on exports.

And as pipelines allow access to its west coast, and thus the growth area of Asia, ample Canadian oil could become the benchmark for the Pacific Basin

With Canada expected to grow its production to 6.5-m barrels a day from just half of that today, it could first become a supplier of crude oil to NW Europe, competing with oil from the Urals, providing a higher netback to Canadian producers than is currently the case given the bottlenecks to move crude oil from Alberta to higher value markets. But eventually, once pipelines to the Pacific are in place Canadian producers should become significant suppliers of crude oil to the fastest growing market in the world – the Pacific Basin. If economic logic prevails, exports to the Pacific Basin should be Canada's growing supply of syncrude, while heavier crude streams, like Western Canada Select (WCS) crudes, should focus on the US Gulf Coast refining sector, which is built to process these low gravity and sour crudes. That is more than a little ironic, given that environmental opponents to the import of Canadian syncrude and to the construction of new pipelines from Canada to the US have focused their attention on banning imports of "dirty" Canadian syncrude, alleged to involve more intense greenhouse gas-emitting production processes.

One additional consequence of this evolving North American situation is that Canada's base-load supply of perhaps 1-m b/d of syncrude to the Pacific Basin (more if takeaway capacity and thus prices allow) – could potentially be delivered to markets in China, Japan, Korea, Singapore and elsewhere, and could take on the qualities of a new benchmark. Especially to the degree sales of Canadian crude to the Pacific are on a spot basis, a new benchmark is likely to emerge against which crude suppliers from the Middle East price their crude into the Pacific Rim. Russian crudes could also play this role and no doubt Moscow would like to see exchange trading of Russian "ESPO" (East Siberia-Pacific Ocean pipeline) oil on the St. Petersburg Exchange. But Canadian crude — traded on more financially friendly exchanges than anything likely to be developed in Russia — should win the day.

At the time of writing, oil prices remain high, with Brent reaching $117/bbl levels, having marched up from $105 levels in early December. The US revolution has been happening faster than expected, so what is holding up prices? The main reasons are a combination one-off factors and market perceptions. The reduction in Saudi production in 4Q'12 and into 1Q'13 spooked the market despite official Saudi explanations that part of the reason was a reduction in domestic requirements for power generation coming off summer highs by some 500-k b/d. Another factor has been reduced refinery demand, especially in Asia, due to refinery turnarounds. Similarly, the increase in Chinese imports and refinery runs towards the end of 2012 provided an impression, combined with higher GDP growth, that Chinese growth had returned, and with it, old patterns of consumption. But this looks unlikely on both counts — China should not be growing at double-digit rates going forward, and the emerging Chinese economy is far less commodity and energy intensive than the economy of the past decade. It is important to note that despite an escalation in disruptions from both OPEC and non-OPEC producers since February 2011, prices have been remarkably range-bound and seasonal. Growing supply both in OPEC and non-OPEC, with Iraq and the US leading the charge, should start to put downward pressure on prices going forward.

We start our exploration of these global issues by focusing on the local markets emerging and what to expect as a result in the years ahead, before turning to the geopolitical impacts on the US, OPEC and Russia.

Part I: The dynamic duo charge ahead, impacting markets and prices

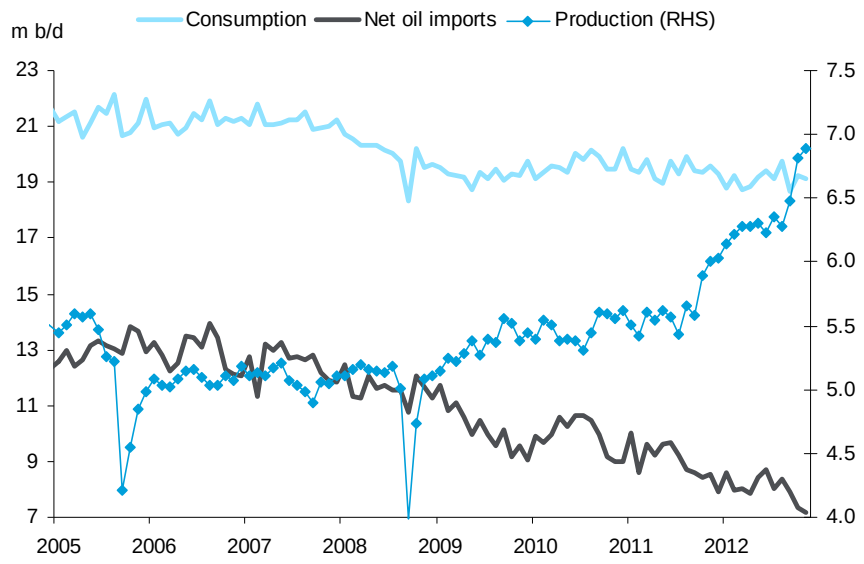
The US and Canada have until recently been the fastest growing oil producers in the world – this past year Iraq overtook Canada for second place and is set to keep that pole position alongside the US. Total US domestic supply is a combination of different sources: crude oil and field condensates, natural gas liquids (NGLs), renewable fuels (fuel ethanol), and refinery processing gains (which is a volumetric increase that takes place during the refining process, and has increased modestly over time). This total supply was 8.3-m b/d in 2007, growing to 9.5-m b/d in 2010, and 11.2-m b/d as 2012 closed, making the US the largest oil producer in the world as of last year. This is especially noteworthy as the period saw declines in the US Gulf of Mexico in the wake of the BP Macondo disaster. As drilling in the Gulf of Mexico has resumed, the current growth rate of total US output has accelerated.

With falling US consumption of oil — due to demographics, fuel efficiency, and going forward, substitution to non-oil fuels — the US net import position is plummeting. This is as US net oil product exports have reached record highs, overtaking Russia as the largest oil product exporter in the world. Total net imports of crude oil and petroleum products were at a record monthly level of 13.4-m b/d in 2006, but by 2010, this had fallen to 9.4-m b/d. In November 2012, net oil imports ran as low as 6.7-m b/d, as gross product exports rose from 1.43-m b/d in 2007 to over 3.4-m b/d by end-2012.

The numbers are clear: the US has reduced its pull on oil markets by 5-m b/d over the last five years, as production has surged and consumption eased

As a result, US net total petroleum imports have fallen by 5-m b/d in five years and 6.3-m b/d from the widest level in 2006. Step back for a moment: this is more than the production of almost every country in the world, except Saudi Arabia, Russia and the US itself. It is decidedly more than the production of Canada, China, Iran, Iraq, Kuwait, Norway, the UAE or Venezuela. This shrinking pull of the US economy on the international oil sector has just begun to have important consequences politically and geopolitically. More tangible impacts are about to unfold in 2013 and in the remaining years of this decade.

Figure 1. As crude production has surged while demand is in structural decline, net imports have been falling substantially

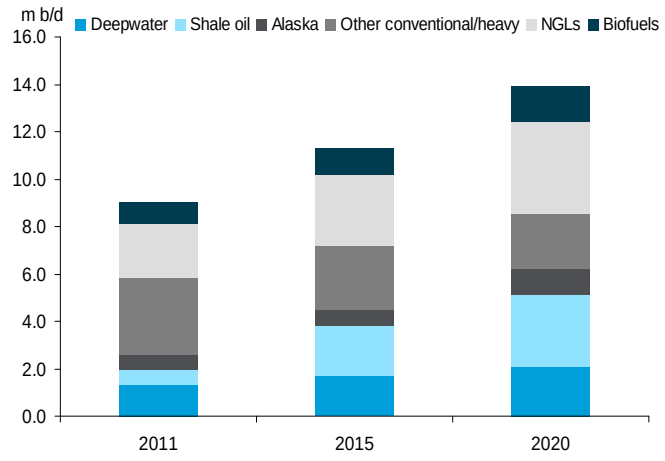


Source: EIA, Citi Research

Canada and Mexico can contribute further to regional supply growth this decade

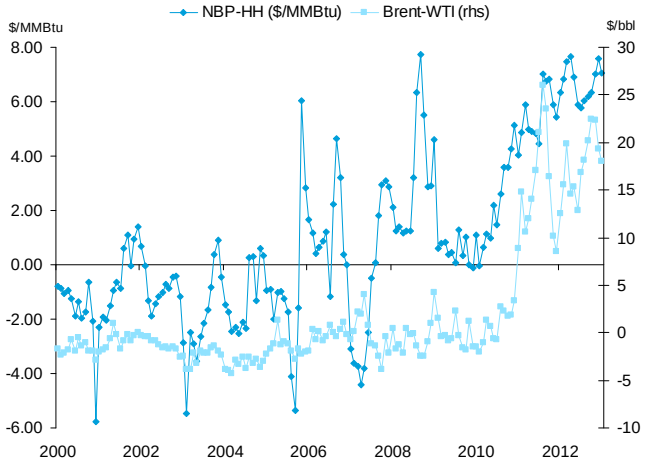
Canadian oil production growth is not far behind, with oil sands production likely to contribute some 200-k b/d of growth every year for the next 10, perhaps 20, years, though facing near-term problems as infrastructure bottlenecks bedevil producer economics, so the outlook for 3.7-m b/d of oil sands by 2020 could yet fall short. But combined with tight oil and NGLs growth, Canadian total liquids production could still reach 6.5-m b/d. Mexico, too, after seeing a plateauing of production well below 3-m b/d today, could perhaps grow to 3.5-m b/d by 2020, on the back of onshore extensions of the Eagle Ford shale formation into Mexico, conventional onshore sources, as well as offshore Gulf of Mexico deepwater production.

Figure 2. US production could grow over +4-m b/d to 2020, driven by shale and some deepwater



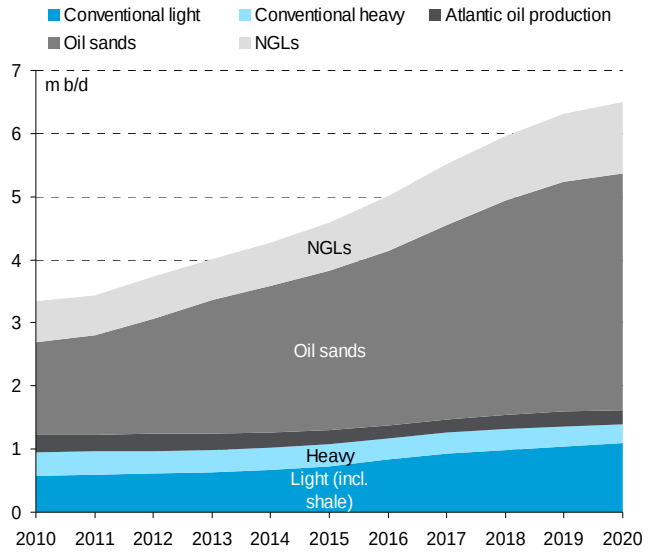
Source: Citi Research

Figure 3. US oil prices have followed gas prices in disconnecting from the world – Brent-WTI goes the same way as NBP-HH natural gas prices



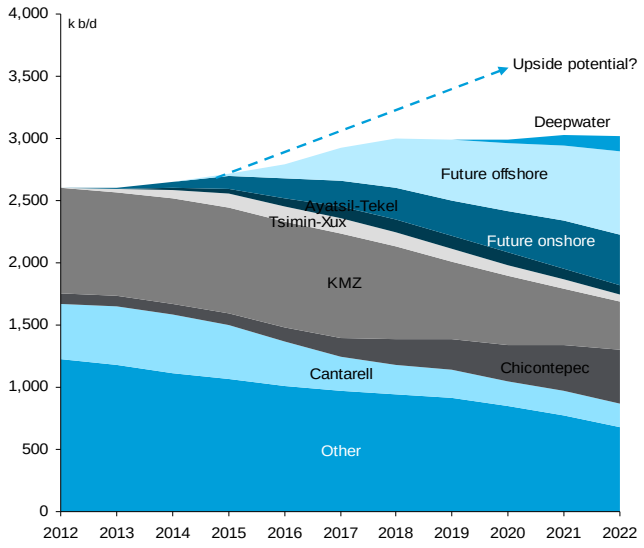
Source: Bloomberg, Citi Research

Figure 4. Canadian production could grow almost +3-m b/d between 2012 and 2020, driven by oil sands, but also tight oil and NGL



Source: CAPP, Wood Mackenzie, Citi Research

Figure 5. Mexico too could see growth of more than 0.5-m b/d to 3.5-m b/d or more by 2020



Source: Pemex, Citi Research

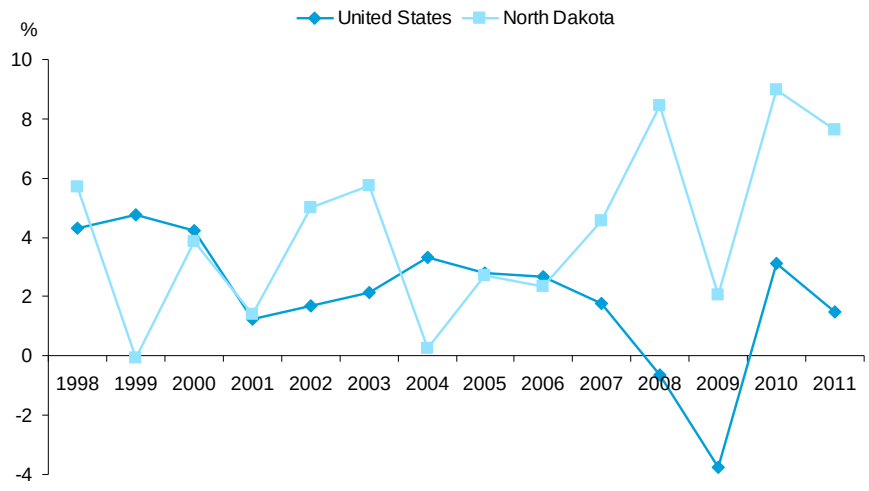
This production growth from North America looks bound to place considerable pressure on global oil prices in the half decade ahead, even if they were not the only fast growing new source of supply. But Iraq's promise to increase production to a level that could rival Saudi Arabia might now also be unfolding. Last year, Iraqi production grew by close to 500-k b/d. Only internal security and deteriorating relations between the northern Kurdistan Regional Government (KRG) and the heartland of Iraq might prevent an additional +500-k b/d per year for five years or more to come and pressure prices even more.

The economic impacts for the US are positive — for GDP, jobs, and the dollar — and come at a particularly opportune time

The impact of this newfound bounty for the US is positive, and comes at a particularly welcome time as the US remains in a period of slow economic recovery. The economic consequences for the US were projected and discussed in detail in "*Citi GPS Energy 2020: North America, the New Middle East?*". The top line impacts of the hydrocarbon production and consumption projections saw real GDP increased by 2% to 3.3% by 2020, 2.2 to 3.6 million more jobs created on net, and a strengthening of the US dollar by 2% to 5% in real exchange rate terms (above what would otherwise have been the case).

Some of these impacts to date can be seen in the microcosm of the US state of North Dakota, where the phenomenal growth of hydrocarbon production in the Bakken shale play has boosted the state's economy. As nationwide real GDP growth trundles on at around 2%, North Dakota has been the fastest growing area in the country at 9% and 7.6% in 2010 and 2011, respectively (nationwide US real GDP growth was 3.1% and 1.5% in 2010 and 2011, respectively), and with unemployment at ~3% in September 2012, the lowest in the country and well below the nationwide level of 7.8% in the same month. North Dakota's stellar economic performance today can be compared to that of just a few years ago, before the shale boom – over 2000-2006, North Dakota real GDP growth averaged 3%, just above the average nationwide US real GDP growth of 2.6% over the same period.

Figure 6. US nationwide real GDP growth vs. North Dakota real GDP growth (1998-2011)



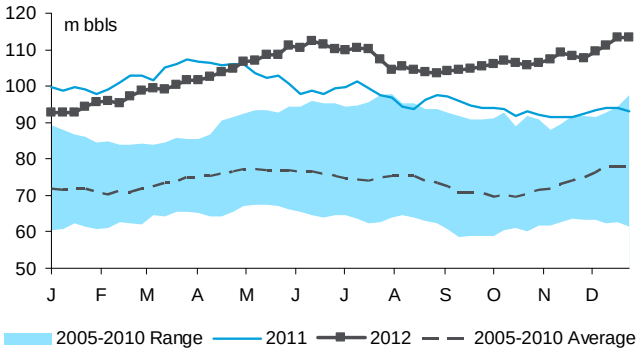
Source: US Bureau of Economic Analysis, Citi Research

This domestic hydrocarbon cornucopia should continue to push out crude oil imports, impacting those oil suppliers that have enjoyed a thriving US market for the longest time. But to see how, when, and by how much this impact might affect suppliers, requires looking at the domino effect of stranded new oil production, the transportation of crude oil to domestic or North American refineries to process into finished petroleum products for domestic use or export, or even the direct export of crude oil.

Understanding the impacts requires an examination of upstream production, midstream pipeline and rail infrastructure, downstream refinery demand, inventories and price differentials

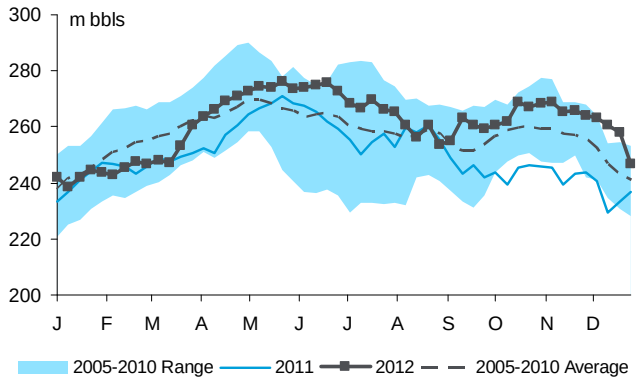
As this new production hit infrastructure bottlenecks, crude stocks bulged in Cushing and PADD II, causing price dislocations, with new price relationships developing between WTI and Brent, but also physical crude prices on the Gulf Coast (Louisiana Light Sweet, or LLS), in the US midcontinent (such as Bakken at Clearbrook, Minnesota) and western Canadian oil sands-derived crudes in Alberta (Syncrude Sweet Blend at Edmonton, and Western Canada Select, or WCS, at Hardisty).

Figure 7. PADD II* crude inventories well above historical range...



Source: EIA, Citi Research
* PADD II = Petroleum Administration for Defense District – Midwest region

Figure 8. ...but US crude inventories ex-PADD II remain within the 5-yr range (with the majority in PADD III* at ~170-m bbls at end-2012)



Source: EIA, Citi Research
* PADD III = Petroleum Administration for Defense District – Gulf Coast region

This report looks at this process, in order to locate the end game of these new dynamics. In turn, the geopolitical picture painted in this end game shapes potential geopolitical impacts in the long-term.

Citi has projected the US and Canada to become a net exporter of crude oil and petroleum products, with perhaps a substantial petroleum surplus by 2020. This looks to impact those countries which have enjoyed US oil import markets, as well as those of which new North American export supply might displace: West Africa, the Middle East, Venezuela, Mexico and Russia.

Winners and losers

In the next five years, growing output in US, Canada and Mexico will have further impacts on global oil and gas markets – and the face of geopolitics. Rampant US shale oil production and upgraded Canadian syncrude growth has already created a glutted situation in the US midcontinent.

(1) As light sweet crude imports dwindle, West Africa is hardest hit

In the first phase going forward – as pipeline, rail and waterborne transportation allows US shale oil to reach light sweet crude markets on the Gulf Coast, East Coast, West Coast and eastern Canada – light, sweet crude imports into the US are pushed out. West African producers have been the main suppliers of light, sweet crude to the US and Canada, as North Sea production has shrunk, and should see this import market dwindle. Eastern Canada would be reached by waterborne crude exports out of the Gulf Coast, for which licenses have already been issued by the US Department of Commerce under the NAFTA free trade agreement. Already as 2013 opened, significant shifts were under way on trade flows. More US crude was entering Canada, not only pushing out West African crude, but also pushing Canadian offshore crude supply into Europe and away from Canadian refiners. At the end of this phase, Louisiana Light Sweet (LLS) becomes a better marker for Atlantic Basin light sweet.

(2) When Canadian supply can reach the US Gulf Coast, heavier crudes from Venezuela, Mexico and the Middle East are impacted

In the second phase, western Canadian upgraded syncrude and WCS-related bitumen blends should grow robustly and increasingly reach the US Gulf Coast as pipeline capacity – and rail – is built out by 2014-15. Heavy Canadian crudes would compete with Venezuelan, Mexican and Middle Eastern heavy crudes, pushing out heavy Gulf Coast imports. Rail transportation could bring these crudes from Canada to Californian markets, impacting imports there too. Before westward pipeline options are built (likely not until 2017-18 or later), Canadian crudes may be the only other crude exportable from the US Gulf Coast – other than exports from the US to Canada, current rules also allow for re-export of foreign-origin crude oil, such as that from Canada. Syncrude exported from the Gulf Coast could compete with Urals (a Russian export oil mixture), and receive a netback price to Alberta of Urals minus ~$10.

(3) Western Canadian crudes have suffered from being the furthest along the supply chain from the US Gulf Coast, but westward pipelines to the Pacific Basin unlock new markets

In the third phase, Canadian crudes begin to be exported from Canads's west coast after two key pipelines are approved and built. As these crudes reach the lucrative Pacific Basin markets, Canada could enjoy higher netbacks than, say, previously via US Gulf Coast exports. Canadian syncrude could find itself competing with Russian ESPO crude for the role of Pacific Basin benchmark, keeping prices depressed for Middle East crudes in the fastest growing market for oil in the world. Middle East crude to the Pacific Basin could end up being priced off of Pacific benchmarks, not Oman/Dubai, causing loss of a ~$1-2/bbl premium.

OPEC is thus fundamentally challenged by the North American supply revolution as a result of on-the-ground changes in production rather than by politics or intent, and while the US could end up stronger and international oil prices could see a deflationary period, new instabilities could also come to the fore. Oil producers increasing their social spending programs to assuage restless young, unemployed populations look to face higher and higher fiscal breakeven prices for oil – already well over $100 for many countries – even as global oil prices look to be capped at $90/bbl this decade. There remains a real possibility that such oil producing countries could, in the extreme case, become failed states. The following sections run through these three phases of market impacts in greater detail. For the geopolitical impacts, see the second half of this report, "Part II: The result is a very big difference for foreign policy and geopolitics."

Phase I: West Africa feels the squeeze as a new pecking order for light, sweet crude emerges

2013 promises to be the most dramatic year of change ever in light sweet crude flows, as some 1.6-m b/d of new US pipeline capacity in the US and as much as 600-k b/d of new rail capacity between the US and Canada is opened. West Africa has been a key supplier of light, sweet crude to the US, but as domestic light, sweet crude production has burgeoned, West African imports have already been hard hit. US crude imports from Africa were as high as 2.4-m b/d in 2007 (with 1.6-m b/d from Angola and Nigeria alone) and Canadian imports of African crude added another ~200-k b/d as well as 300-k b/d from the North Sea, but these have all been dropping since, particularly precipitously since late 2010. By end-2012 US crude imports from Africa accounted for around 1.1-m b/d, and were below 0.7-m b/d from West Africa. It looks like the market for West African crude on the US Gulf Coast, the US East Coast, and eastern Canada could be taken over in the next few years, with the US Gulf Coast no longer importing any light, sweet crude by late this year. The key drivers for this are growing domestic light, sweet production, debottlenecking of crude transportation infrastructure, and growing US crude exports to Canada. With these changes, LLS could become the most reflective crude marker for the Atlantic Basin.

Bakken and the US midcontinent

North Dakota production could grow to as much as 1.2-m b/d as soon as 2015, with late 2012 levels peaking temporarily at ~750-k b/d as of October 2012 before dropping in November to 730-k b/d due to harsh winter weather, but still up over 250-k b/d year-on-year. Local pipeline, rail and truck infrastructure growth in the Bakken area – used to gather crude, plus to connect with main pipelines, local refineries or directly to destination markets – has proceeded at a rapid clip, but pipelines alone are not enough, with rail making up the shortfall and likely to do so until after 2015, when Bakken access to two planned pipelines, the Keystone XL pipeline (up to 100-k b/d) and Enbridge Sandpiper (up to 325-k b/d), adding a total of +425-k b/d of capacity.

Figure 9. Bakken pipeline and rail takeaway capacity (k b/d, year-end 2012), planned and proposed

	2011	2012	2013E	2014E	2015E	2016E
Butte Pipeline	145	160	160	160	160	160
Butte Loop (late-2014)	-	-	-	110	110	110
Tesoro Mandan Refinery (mid-2012)	58	68	68	68	68	68
Enbridge Mainline North Dakota	185	210	210	210	210	210
Enbridge Bakken Expansion (1Q'13)	25	25	145	145	145	145
Plains Bakken North (4Q'12)	-	-	75	75	75	75
High Prairie Pipeline	-	-	-	150	150	150
Enbridge Sandpiper (1Q'16)	-	-	-	-	-	225
TransCanada Keystone XL (2015)	-	-	-	-	100	100
Pipeline takeaway capacity	413	463	658	918	1,018	1,243
EOG rail, Stanley, ND (up to 90-k b/d)	65	65	65	65	65	65
Dakota Plains, New Town, ND	40	40	40	40	40	40
Various sites in ND (estimated)	30	30	30	30	30	30
Rangeland COLT, Epping, ND (Q2 2012)	-	120	120	120	120	120
Hess Rail, Tioga, ND (up to 120-k b/d)	-	60	60	60	60	60
Bakken Oil Express, Dickinson, ND	100	100	100	100	100	100
Savage, Trenton, ND (2Q'12)	-	90	90	90	90	90
Enbridge, Berthold, ND (4Q'12)	-	10	80	80	80	80
Great Northern, Fryburg, ND (4Q'12)	-	60	60	60	60	60
Musket, Dore, ND (2Q'12)	-	60	60	60	60	60
Plains, Ross, ND	20	20	65	65	65	65
Van Hook, ND	-	35	70	70	70	70
Basin Transload, Zap, ND (estimated)	20	40	40	40	40	40
Rail takeaway capacity	275	730	880	880	880	880

Source: North Dakota Pipeline Authority, company reports, Citi Research

For much of 2013 and 2014, rail to the Gulf Coast, but also increasingly to the East and West Coasts of the US, and the east coast of Canada, should move the marginal barrel. This suggests Bakken and related differentials to waterborne crudes like LLS or Brent remain at or higher than rail transportation costs. For reference, Tesoro indicated that rail transportation costs from the Bakken were $15 to the Gulf Coast, $16 to the East Coast, $9.75 to Washington state and $13-14 to California. The price of Bakken crude has momentarily moved – and could at times continue to move – to a premium to WTI, as local supply issues affecting Bakken, syncrude and even Gulf Coast Capline volumes to the Midwest refining centers appear on occasion, while at the same time Bakken crude was able to reach waterborne markets willing to pay higher prices. As the table above shows, rail loading capacity at the origin reached over 700-k b/d by end-2012 and could attain almost 900-k b/d over 2013. And rail receiving capacity is growing quickly, with around 450-k b/d of capacity on the Gulf Coast and at a few refineries in the Midcontinent, but also approaching 900-k b/d on the East Coast, where refiners have had strong incentives to run local crude instead of expensive West African imports; several refiners have announced plans for or already have rail unloading facilities, and others are receiving crude via rail to Albany, NY which is then barged to its final destination. Note that the table below only includes reported volumes, so actual capacity could be higher.

Figure 10. Crude-by-rail receiving capacity at refineries and terminals, by region – only reported volumes contribute to totals (k b/d end 2012)

		2011	2012	2013	2014	2015	2016
Plains All American (formerly USDG)	St. James, LA	65	130	130	130	130	130
EOG, Nustar	St. James, LA	20	130	130	130	130	130
Savage/KCS	Port Arthur, TX	-	70	70	70	70	70
Nustar	Texas City, TX	-	3	3	3	3	3
GT Logistics	Port Arthur, TX	-	80	80	80	80	80
EOG	San Angelo, TX	-	5	5	5	5	5
Flint Hill	Odessa, TX	-	5	5	5	5	5
CrossTex Energy	Geismar, LA	-	15	15	15	14.5	14.5
Delek	El Dorado, AK	-	10	10	10	10	10
Rangeland/Flint Hill Pine Bend	Pine Bend, MN						
TOTAL GULF COAST, MIDCONTINENT		85	448	448	448	448	448
Rangeland/Tesoro	Anacortes, WA	-	40	50	50	50	50
Phillips 66 refinery	Ferndale, WA	-	20	20	20	20	20
US Oil and Refining Tacoma refinery*	Tacoma, WA						
BP Blaine refinery	Blaine, WA	-	-	60	60	60	60
BNSF to Alon Bakersfield refinery	Bakersfield, CA						
TOTAL WEST COAST		-	60	130	130	130	130
Sunoco/Carlyle (120 in 2Q'13, 180 late'13)	Philadelphia, PA	-	20	120	180	180	180
Delta (Apr 13)*	Trainer, PA						
PBF (expand to 150-k b/d over 2013, with 80-k b/d heavy and 70-k b/d light))	Delaware City,DE	-	40	150	150	150	150
Global Partners rail-to-barge	Albany, NY	-	160	160	160	160	160
Buckeye Partners, rail-to-barge	Albany, NY	-	-	135	135	135	135
Buckeye Partners*	Perth Amboy, NJ						
Plains All American (3Q'13)	Yorktown, VA	-	-	130	130	130	130
Enbridge (3Q'13, expandable mid-2014)	Philadelphia, PA	-	-	80	160	160	160
Hess (from Tioga, ND, supply others)*	Port Reading, NJ						
Irving (35-k b/d shipped from Albany)	St. John, NB	-	70	70	70	70	70
TOTAL EAST COAST (INC. CANADA)		-	290	845	985	985	985
TOTAL RECEIVING CAPACITY		85	798	1,423	1,563	1,563	1,563

Source: Reuters, company reports, Citi Research * Project plans announced but volumes not reported.

Over half of North Dakotan crude production – around 480-k b/d at end-2012 – is estimated to have been transported by rail. Much of this connects to St. James, Louisiana, as well as Port Arthur, Texas and Mobile, Alabama. Other volumes have been growing: ~10-k b/d to Delek's 80-k b/d El Dorado, Arkansas refinery; amounts to Tesoro's 120-k b/d Anacortes, Washington refinery which has 50-k b/d of rail receiving capacity; and some of the recently resurrected US East Coast refineries – with new receiving capacity also being built there. Even the Irving St. John refinery in New Brunswick, Canada, which has 70-k b/d of rail receiving capacity, is now receiving crude by rail as well as waterborne volumes via the US East Coast; Bakken crude is being railed to intermodal facilities already in Albany, New York, and being built in Yorktown, Virginia, to be barged onto the Philadelphia refineries, as well as up to eastern Canada. Alon's southern California refineries may look to receive railed Bakken and Permian Basin volumes too by the end of 2013.

The growing importance of PADD I (East Coast) refineries as a destination market for Bakken could be seen as recently as during the impact of Hurricane Sandy in the fall of 2012; with East Coast refineries, terminals and ports shut-in preemptively, and later some suffering from outages due to flooding. Railed and barged Bakken crude heading to PADD I needed to be diverted elsewhere and Bakken-Clearbrook physical differentials to WTI weakened considerably.

Rail is relatively expensive compared to pipeline, but its flexibility in reaching varied markets has challenged some pipeline projects. One recent change to the local Bakken pipeline capacity outlook is that ONEOK Inc is no longer going ahead with its Bakken Crude Express pipeline due to lack of customer commitments for the 10-year terms it was looking for. It would have been a 1,300-mile crude pipeline with 200-k b/d capacity moving Bakken crude to Cushing. ONEOK cited rail as the biggest factor in canceling this project, because rail could offer shorter contracts and greater flexibility with respect to destination. Upstream companies have been less willing to sign long-term contracts in the current crude price environment.

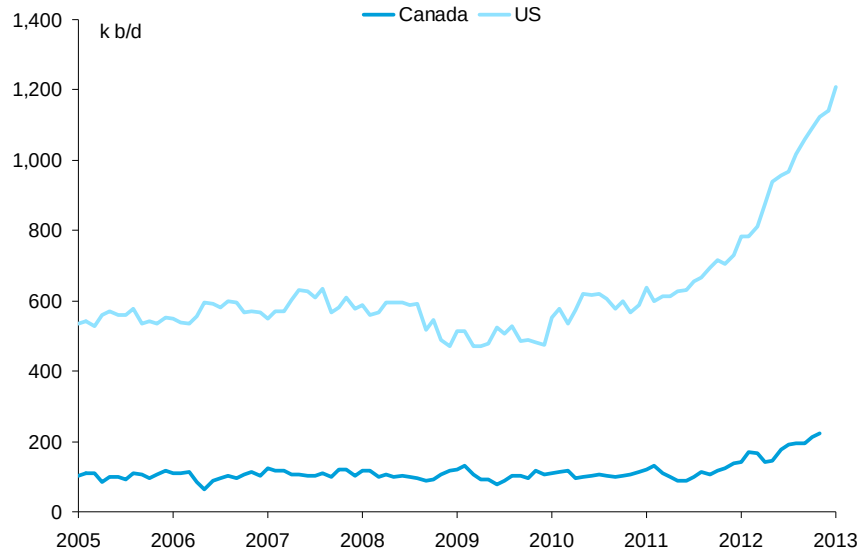
The Eddystone project is a plan to convert the train facility at the Eddystone Generating Station outside of Philadelphia from one capable of handling coal to one that carries Bakken crude oil from North Dakota for use at Philadelphia refiners

Enbridge, Inc. has joined the rail bandwagon, announcing plans to operate a Philadelphia rail terminal through a stake in the Eddystone project, which would be a 120-car unit train facility with local pipeline connections. Eddystone is expected to receive 80-k b/d of volumes by 3Q'13, with the potential for expansion to 160-k b/d by mid-2014. Volumes could be loaded onto barge or pipeline to be transported on to refineries in the area.

Plains All American bought four operating crude-by-rail terminals from US Development Group for $500 million, which included three loading terminals in the Eagle Ford, Bakken and Niobrara shale plays with capacity totaling 85-k b/d, and an unloading terminal at St James, Louisiana with 140-k b/d capacity. Plains is also developing an unloading terminal at Bakersfield, California.

The wholesale migration of a supporting economy for surging North Dakotan oil production has created unique local pressures. Although crude oil is being produced and pumped out of the Bakken, trucks, rail and pipelines are also bringing in water, sand, fracking fluids, tubular steel and other materials. At times, there have been localized shortages of diesel fuel for operating machinery and trucks, causing periodic local price spikes. Given the availability of abundant high-quality crude and local demand, there are plans for local refinery expansions and even greenfield construction plans, though the capacities for these are relatively small. Use of natural gas to power machinery is also growing.

Figure 11. US crude and product railcar loadings have grown over 420-k b/d y-o-y at Jan-13, while Canadian crude railcar loadings have risen 100-k b/d y-o-y at Nov-12 (k b/d, 4WMA)

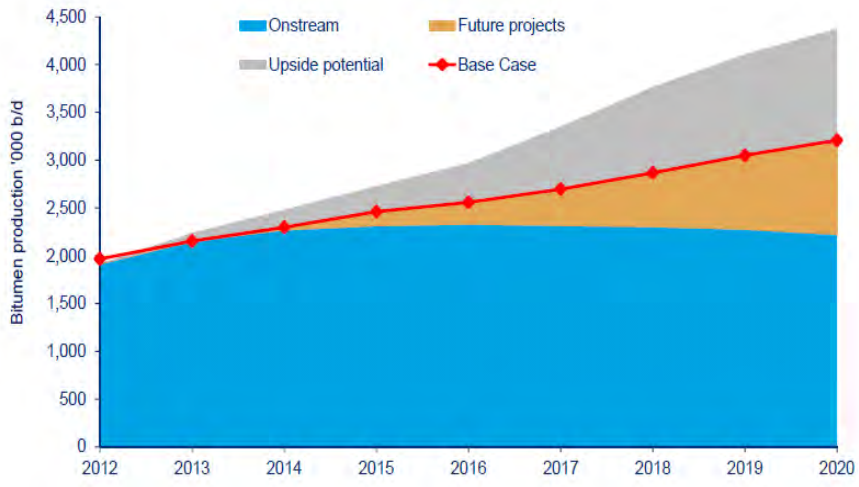


Source: AAR, Statistics Canada, Citi Research

Western Canada

Canadian oil sands production could grow +1.9-m b/d to 3.7-m b/d between end-2012 and 2020, with around 1-m b/d upgraded to light, sweet syncrude in the second half of the decade, depending on upgrader facility build-out and utilization, which remains challenged. Separately, growing volumes of Canadian shale oil would add to light, sweet volumes. With plenty of light, sweet crude being produced "downstream" of Canada – in terms of reaching US midcontinent and Gulf Coast markets – light-heavy differentials should remain problematic for full build-out and utilization of Canadian upgrading and shale oil production. The reversal and extension of the Enbridge Line 9 pipeline and conversion of the TransCanada gas mainline would help western Canadian crude reach the eastern coast and that would be mostly lighter syncrudes. But the major stimulus would be if or when the westward pipelines allow western Canada producers access to Canada's west coast, so that crude can be shipped onward to thirsty Pacific Basin markets.

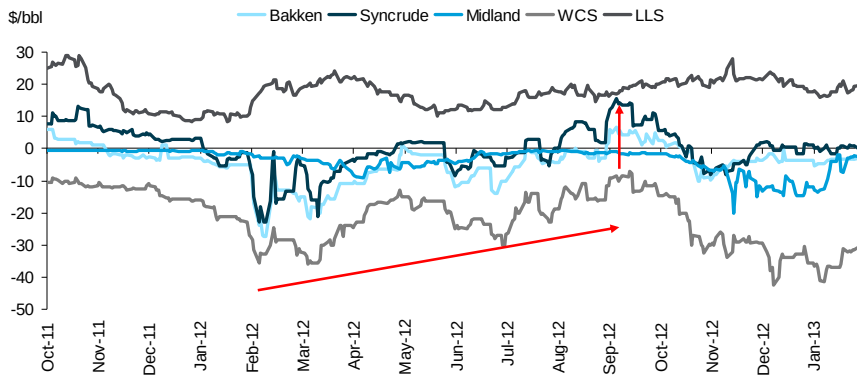
Figure 12. Upside potential for oil sands is substantial, hinging on project delays given prices, which themselves depend on crude outlets to the US Gulf Coast, or Canadian west coast; Woodmac projections range from just over 3-m b/d to well over 4-m b/d by 2020



Source: Wood Mackenzie

Limited takeaway and quite ample supply should keep Canadian syncrude prices at a significant discount to US Gulf Coast LLS to ration production. Bitumen barrels are currently transported by rail at the margin, though increasingly debottlenecked by pipeline via Cushing in the next few years. Short-term fluctuations in supply to the Midwest could still move syncrude to temporary premiums to WTI for now, as can happen with maintenance to Canadian syncrude upgraders and supply via the Capline pipeline from the Gulf Coast. Recently this caused syncrude to move to a premium to WTI, diverting crude from Cushing to Midwest markets. This is the result of WTI being bottlenecked in the US midcontinent, while Canadian and Bakken production find short-term debottlenecking to other markets at times.

Figure 13. US midcontinent cash differentials to WTI ($/bbl) widened as growing supply challenged pipelines, but have narrowed as railed volumes from the Bakken to the Gulf Coast rise, connecting to LLS (in black), though the Sept spike was primarily due to Canadian upgrader outages; weak WCS suggests ample heavy volumes in the midcontinent at end-2012



Source: Bloomberg, Citi Research

Until the TransCanada Keystone XL pipeline is completed – assumed in 2015, though political risks abound – western Canadian production continues to grow and challenge existing pipeline infrastructure, keeping downward pressure on syncrude prices relative to WTI (where barrels should need to be competitive) and certainly LLS (where prices connect to waterborne crudes). With Keystone XL built, syncrude could add to the light crude glut on the US Gulf Coast and seek to be exported (since exports of crude oil of foreign origin are permitted); this is described below in the section *Phase II*. With a 2017-18 completion date for the westward Canadian pipelines to the Pacific Basin a feasibility, Canadian crudes could find higher netback prices in Asia than by exporting from the US Gulf Coast, at which point syncrude could find itself competing with Russian ESPO (described in *Phase III* below).

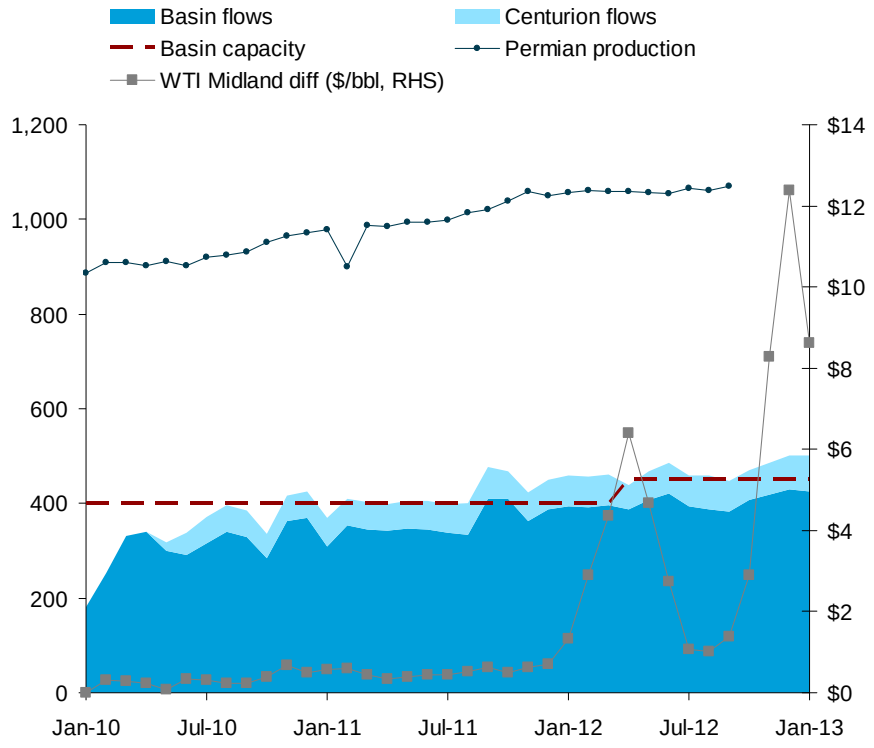
And what about Canadian shale? This could perhaps rise to some 330-k b/d or more by 2017, according to IEA estimates, from 240-k b/d levels today in Saskatchewan, Manitoba, Alberta and British Columbia, helping to reverse Canada's conventional light crude declines. However, the outlook remains uncertain, hinging not only on the favorability of the geology, but also infrastructure limitations; the problem of lack of pipeline capacity south, west or east could stymie this (or encourage this, once completed). Given that western Canada is upstream of east and south-facing options, it would face more problems than the Bakken in getting its crude to markets, at least until a westward option that would finally unlock Pacific Basin markets. Use of very light condensates benefits from robust local demand as local diluent for blending with bitumen to facilitate pipeline transport. The Canadian supply outlook is discussed in greater detail in *Phase II*, below.

The Permian Basin and Eagle Ford

Crude oil production in the state of Texas has been the fastest growing in the US, at 2.14-m b/d in November 2012, up 467-k b/d year-on-year. This has been driven by the double whammy of growth from the Permian Basin (growing around 150-k b/d year-on-year) as well as the Eagle Ford (growing around 300-k b/d year-on-year to 600-k b/d levels at end-2012). Permian Basin production across Texas and New Mexico is an estimated 1.1- to 1.2-m b/d, growing around ~150-k b/d year-on-year and likely remain at this pace going forward. These growing volumes have been a major driver of overwhelming inflows to Cushing, and by late 2012, pipeline capacity

taking this West Texas production to Cushing effectively reached capacity and caused West Texas crude differentials to blow-out before easing as the Basin pipeline was expanded, only to be challenged again a few months later and WTI Cushing to Midland differentials exploded to more than $30 in 4Q'12. But this situation will become revolutionized by mid-2013, as several new pipeline outlets and their potential expansions are opened in 2Q'13. These pipelines will alleviate congestion in Cushing – the only potential pipeline destination until mid-year – by a significant amount.

Figure 14. A major source of growth of inflows into Cushing has come from the Permian Basin, where pipelines, including Basin and Centurion, have filled up and caused WTI Midland prices to fall to heavy discounts to WTI Cushing; but this is also the area that should be progressively debottlenecked by Longhorn, Permian Express and West Texas Gulf pipelines, combined capacity of which can reach well over 400-k b/d by end-2013



Source: Texas Railroad Commission, Bloomberg, Genscape, Citi Research

The Longhorn pipeline's reversal (switching direction from El Paso to Houston to transport crude oil instead of refined products) and expansion could bring some 225-k b/d directly to Gulf Coast refiners and Permian Express pipeline (between Wichita Falls and Houston) could add another 90-k b/d, expanding to 150-k b/d by year-end. By the end of 1Q'13, the West Texas Gulf pipeline (110-k b/d) could take further volumes away from the Permian Basin to the Gulf Coast (at 40-k b/d of capacity to Houston and another 40-k b/d to Nederland, TX) and other parts of east Texas. This is an additional 455-k b/d of capacity potentially arriving on the Gulf Coast by the end of 2013; and able to divert a major chunk of the Permian Basin flows to Cushing (currently running at close to capacity at ~500-k b/d – around 430-k b/d on Basin and 70-k b/d on the Centurion pipeline). The 700-k b/d southern leg of the Keystone XL pipeline allows another hefty chunk of capacity to travel from Cushing to the Gulf Coast by year-end. The Seaway expansion from 150-k b/d to 400-k b/d nameplate capacity has already added actual flows of 145-k b/d (from

135-k b/d levels to current 280-k b/d levels) – although issues at the Jones Creek Terminal at the Texas end of the pipeline may keep volumes below capacity for longer; full debottlenecking might take until mid-2013. We expect some frictions in the process of such a historically huge pipeline capacity build-out in North America, perhaps keeping price differentials wider for longer than expected; in this case, WTI-LLS could be held apart for longer due to a local Houston bottleneck, before reaching the Louisiana price point.

Figure 15. Pipeline capacity projects debottlenecking Cushing and bringing the glut down to the Gulf Coast 4Q'12-4Q'15 (k b/d)

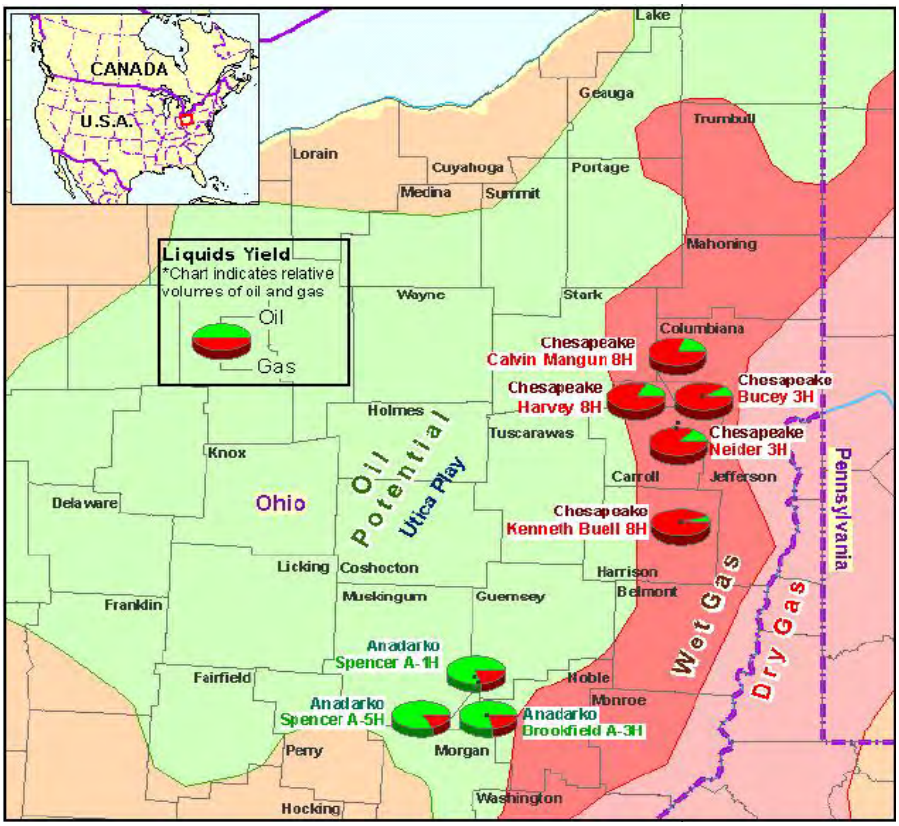
	4Q12	1Q13	2Q13	3Q13	4Q13	1Q14	2Q14	3Q14	4Q14	1Q15	2Q15	3Q15	4Q15
Enbridge/Enterprise Seaway	150	400	400	400	400	850	850	850	850	850	850	850	850
TransCanada Gulf Coast Project	-	-	-	-	700	700	700	700	700	700	700	700	700
Magellan Longhorn	-	135	225	225	225	225	225	225	225	225	225	225	225
Sunoco Permian Express	-	90	90	150	150	150	150	150	350	350	350	350	350
Sunoco West Texas Gulf	-	-	110	110	110	110	110	110	110	110	110	110	110
Magellan BridgeTex	-	-	-	-	-	-	-	-	300	300	300	300	300
Total pipeline capacity	150	625	825	885	1,585	2,035	2,035	2,035	2,535	2,535	2,535	2,535	2,535

Source: Company reports, Citi Research

Eagle Ford crude production reached an estimated 600-k b/d of products at year-end, up from ~300-k b/d levels a year ago, and could continue this pace of growth, adding further local volumes of perhaps another 250- to 300-k b/d by end-2013 alongside the crude glut in the US midcontinent being decongested and brought down to the Gulf Coast. This could back out imports, and bolster exportable volumes to eastern Canada, and reportedly some Jones Act volumes to the East Coast.

Another theoretical safety valve on the US Gulf Coast bottleneck is the Korean market. Korea, like Canada, is a Free Trade Agreement (FTA) ally of the United States. In the case of Canada, export regulations have been written to basically allow an automatic licensing of crude flows to Canada. In theory, registration and licensing requirements for exports to the Republic of Korea would be facilitated once applications are made, and these applications look to be inevitable. Korea has an FTA with the EU which exempts those exports from a 3% tariff ($6.9 million on a 2-m bbl vessel carrying Brent at $115/bbl). Korea is also negotiating an FTA with Canada, which would facilitate exports of Canadian crude west to Asia from the US Gulf Coast before Canadian pipelines west are completed.

Figure 16. Other shale plays in the US and Canada – including the Utica, shown here – provide further potential supply growth potential



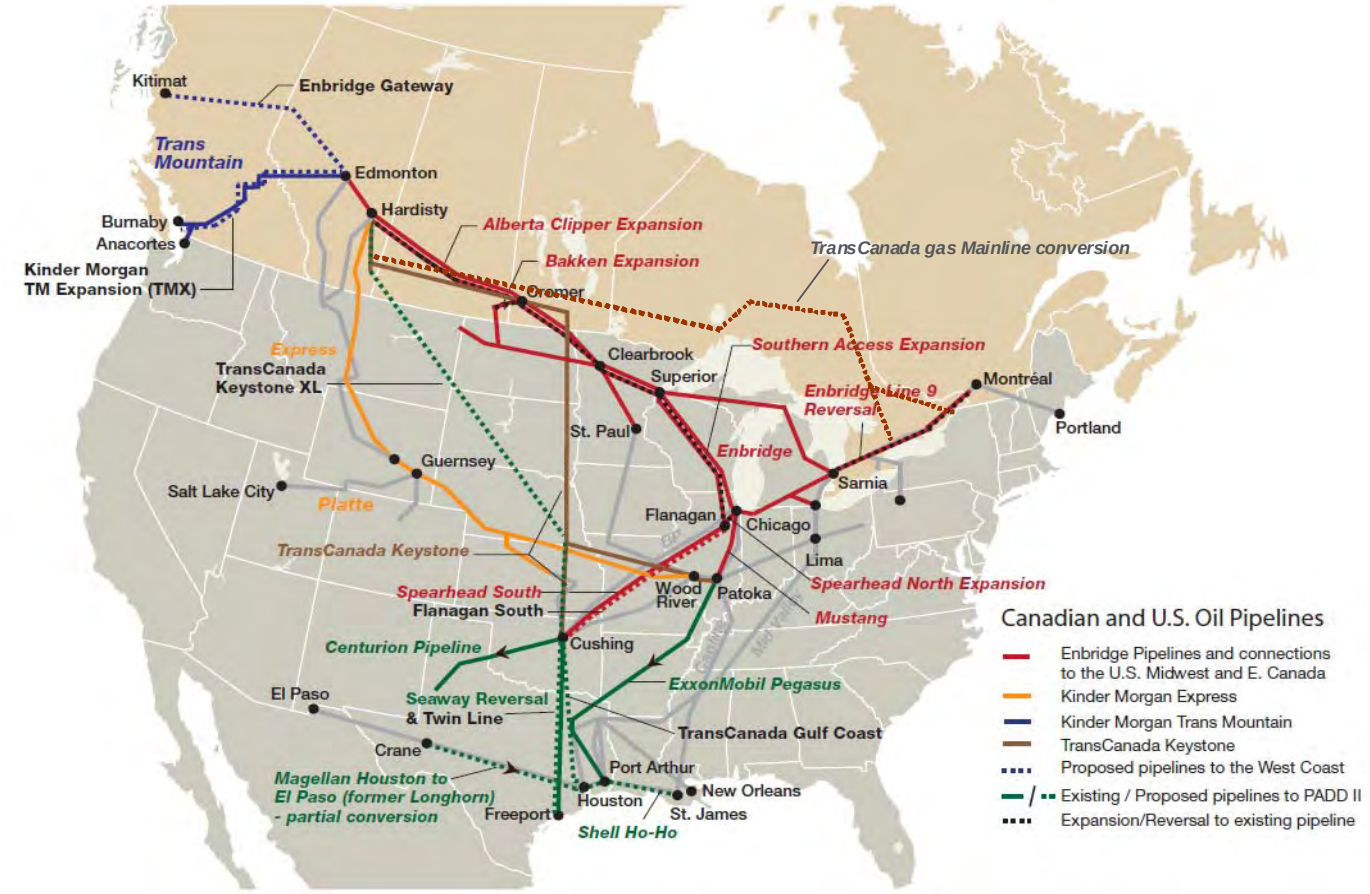
Source: Wood Mackenzie

Refinery upgrades diminish demand for light, sweet crude

The Marathon Detroit upgrade adds new equipment to Marathon's Detroit refinery to process additional heavy crude oils, such as those from Canada – BP is doing the same with its Whiting refinery

Refinery upgrading to take heavier crudes into the US midcontinent continues, decreasing demand for light sweet crude and exacerbating the US light sweet crude glut. The Marathon Detroit upgrade project completing in winter 2012-13 and BP Whiting's upgrade project in Indiana, which began in November with the largest of three crude distillation units (250-k b/d capacity) being switched from sweet to sour crude, and should be back online by July 2013. The complete "modernization" project also includes a new 100-k b/d coker which is now slated to start-up in early 2014 (delayed from 2H'13), meaning the converted CDU may yet be running light sweet crude for longer than originally planned. Detroit should now be processing ~70-k b/d less light sweet crude, and when complete, BP Whiting could be processing ~230-k b/d less light sweet crude, or a total of an additional 300-k b/d of WTI pushed out to other markets.

Figure 17. North American major oil pipelines, planned and proposed



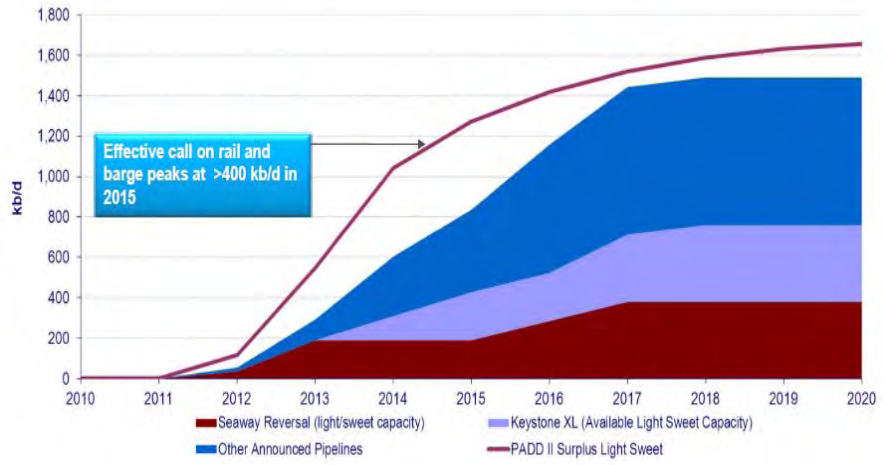
Source: CAPP, Citi Research

Infrastructure build-out starts to push out US imports

As pipelines are built out to debottleneck the US midcontinent, and later, western Canada, light, sweet crude volumes are able to push out all US Gulf Coast light sweet imports, and increasingly challenge East and West Coast imports.

The Seaway pipeline saw its initial reversal in May 2012 (from Cushing to the Gulf Coast), with capacity of 150-k b/d and actual flows of ~135-k b/d, mostly light, sweet crude. The expansion of Seaway to 400-k b/d capacity at the beginning of 2013 begins to bring more Canadian crude to the Gulf Coast, perhaps accounting for the bulk of throughput at first (given the relative strength of syncrude versus WCS suggests that Chicago-area refineries are well supplied with heavy at the start of 2013 but short light, which could mean more heavy volumes reaching Cushing to move to the Gulf Coast). Pipelines diverting Permian Basin crudes away from Cushing and to the Gulf Coast also expand in mid-2013 by some 400-k b/d, easing the US midcontinent glut further and bringing more volumes to the US Gulf Coast. TransCanada Cushing-to-Gulf Coast leg is likely to be ready by late-2013, and adds another 700-k b/d of capacity from Cushing to the Gulf Coast, which could ramp-up to 830-k b/d with the full Keystone XL completion. Mid-2014 should see the "twinning" of the Seaway pipeline to 850-k b/d of capacity, firmly bringing the WTI-LLS spread in to pipeline costs of ~$3/bbl, local Gulf Coast bottlenecks notwithstanding. The end of this phase comes when TransCanada Keystone XL is completed, perhaps by 2015, whereby the pipeline unblocks further syncrude – and WCS – volumes all the way from western Canada to the Gulf Coast via Cushing.

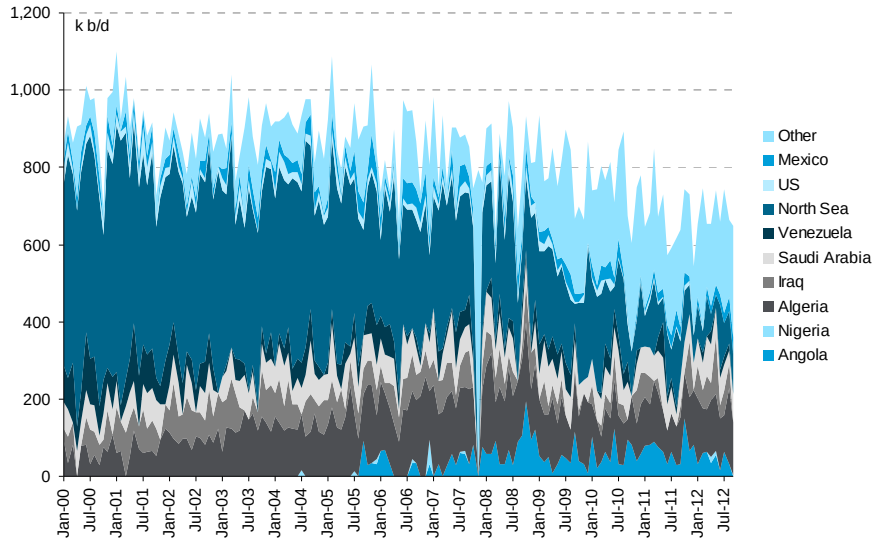
Figure 18. The PADD II light sweet surplus could still require rail and barge to move the marginal barrel to PADD III even with the massive pipeline additions over 2013-15; in the below scenario, Woodmac assumes only 50% of capacity is used for light sweet (except light crude dedicated lines), reducing substantially the capacity available to clear the light sweet glut



Source: Wood Mackenzie

In total, this is ~600-k b/d of additional capacity to the US Gulf Coast by mid-2013 and a cumulative 1.6-m b/d of new capacity by end-2013, well over the 300-k b/d of remaining light, sweet imports to PADD III, especially when combined with local Eagle Ford production growth. 2014 adds the Seaway twinning (+450-k b/d to 850-k b/d total) and the Permian Basin diverting BridgeTex (300-k b/d) for another +750-k b/d of capacity. With full pipeline capacity to the Gulf Coast, rail volumes to St James loses out to cheaper pipeline transportation, but US light, sweet production and Canadian syncrude volumes should continue to grow and challenge pipeline capacity further into the future. In fact, if pipelines were to move the marginal barrel, raising prices received by North American producers, this would incentivize production further, driving new volumes that would, over time, begin challenging infrastructure again. This, and continued favorable economics to transport crude to the East and West Coasts and Canada, should mean rail retains a significant role.

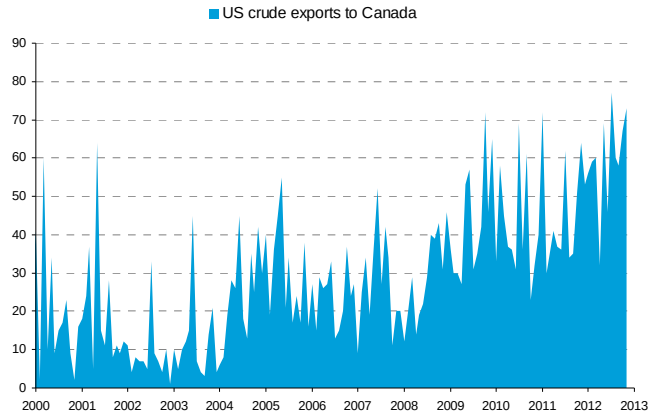
Figure 19. Canadian crude imports by source (k b/d)



Source: IEA, Citi Research

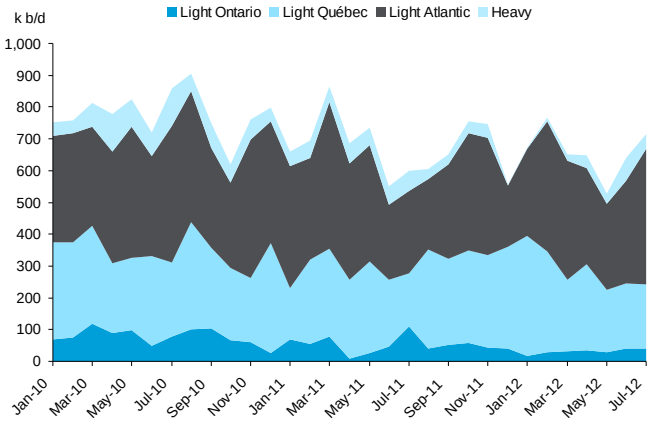
By the end of 2013, US exports of crude oil to Canada (one of the few cases where US crude exports are allowed; this is discussed in greater detail later) could quadruple to 200-k b/d or more as larger and larger waves of supply of light, sweet crude from local US Gulf Coast production, new pipeline capacity from the US midcontinent to waterborne areas, and rail capacity grows to take similar light, sweet crude either directly to eastern Canada or to eastern areas from which oil can be shipped onwards over water to Canada. As well as crude oil, very light condensates from Texas' Eagle Ford are also likely to see their way to Canada by ship from Texas and Louisiana, to blend with Canada's oil sands bitumen to create a crude similar to WCS and other heavier crudes. By 2014, there is likely to be no more than a trickle of imports of West African crudes into Canada and further reduction of imports into PADD I.

Figure 20. US crude exports to Canada at sub-100-k b/d levels but could quadruple to over 200-k b/d as railed volumes and shipped volumes out of the US Gulf Coast grow



Source: EIA, Citi Research

Figure 21. Canadian crude imports by API gravity, region – the ~600-k b/d light crude import market in Eastern Canada is an opportunity for expanding US light sweet crude exports to push out expensive West and North African and Brent crudes



Source: Statistics Canada, Citi Research

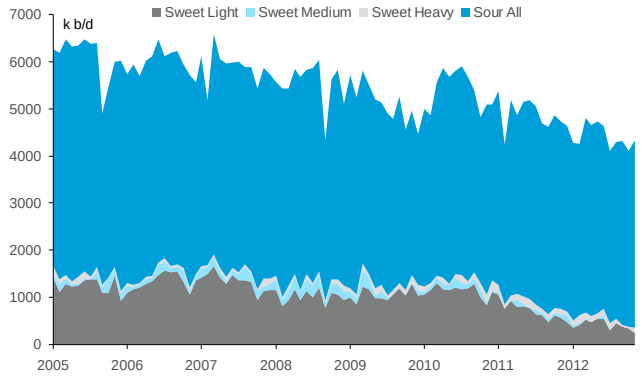
West-to-east pipelines are also being developed, with the key ones including Enbridge's Line 9's reversal and the TransCanada East Coast Pipeline Project. The Line 9 reversal would be for the Sarnia, Ontario to Montreal, Quebec line – with capacity of 240-k b/d – allowing western Canadian crude to reach all the way to the Imperial Nanticoke refinery, as well as a further extension proposed to Portland, Maine. It could also facilitate small export volumes to Europe. Line 9 is targeted to see partial reversal in early 2014 to Hamilton and, pending regulatory approvals, there should be considerable economic pressures to reverse the whole line thereafter.

TransCanada is looking to convert its gas mainline to some 625-k b/d of crude use from Hardisty, Alberta to Montreal, Quebec, perhaps extending it as far as the Irving St. John refinery in New Brunswick, or potentially even exporting from Canaport to Atlantic Basin markets. The pipeline reportedly has already found good interest from potential shippers. Much of the pipe is already in the ground and only 65 miles of new right of way are needed, so the project could take just two years to complete. In the meantime, Cenovus is reportedly moving 5- to 6-k b/d of western Canadian light crude to the Irving St. John refinery by rail, and this could ramp-up further to 10-k b/d in 2013.

With westward and Gulf Coast-bound pipelines all facing substantial political obstacles, other blue sky ideas have been touted. One is to transport crude by rail over 1,000 miles to Alaska, then join the underutilized TransAlaska Pipeline (TAP) to reach Valdez and be exported to Pacific Basin markets. In a 2007 study, BC-based Generating for Seven Generations (G7G) estimated project costs of $8.4 billion for 1.5-m b/d of rail capacity, and $10.4 billion for 5-m b/d of rail capacity along this route.

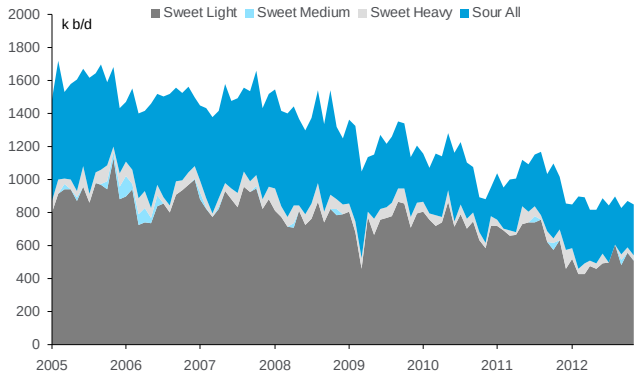
Overall, wide crude oil price differentials between regions with infrastructure bottlenecks should be eased as new pipelines and rail loading and receiving capacity are built out, allowing US and Canadian light sweet crude production to reach the US Gulf, East and West Coasts, as well as eastern Canada. Light sweet crude imports into these areas should be steadily pushed out.

Figure 22. PADD III crude imports by quality – the decline driven by light, sweet crude imports, down to 300-k b/d levels in November 2012



Source: EIA, Citi Research

Figure 23. PADD I crude imports by quality – light, sweet crude imports were around 500-k b/d in November 2012

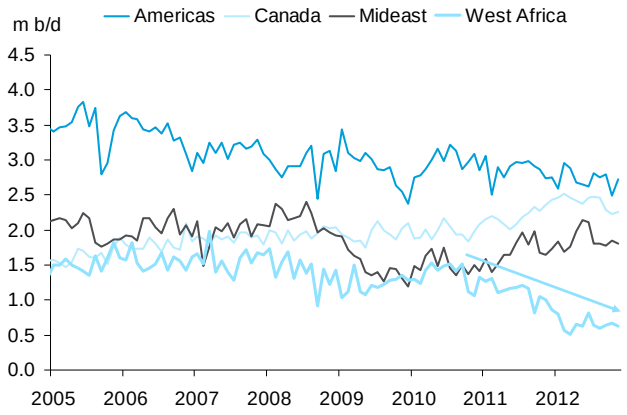


Source: EIA, Citi Research

West Africa and Northwest Europe feel the squeeze

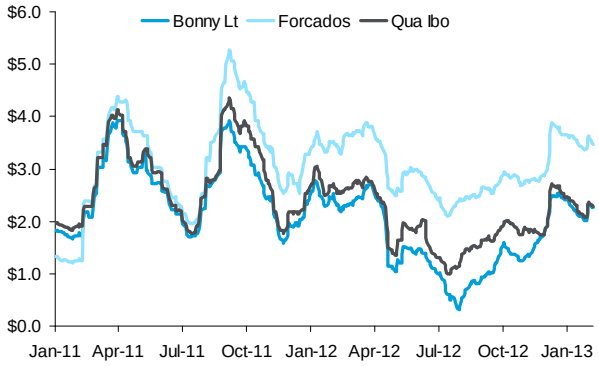
As railed Bakken volumes to the East and West Coasts continue to grow, the East Coast could see its current ~500-k b/d level of light, sweet imports backed out. The West Coast could see its ~200-k b/d of light sweet imports backed out as rail transportation increases. On the US Gulf Coast light, sweet crude imports are down to ~300-k b/d levels, and are likely to be reduced to a trickle of equity barrels by end-2013 as pipelines debottleneck the US midcontinent and local Texas output grows. And crude export from the Gulf Coast of US to eastern Canada is now a 600-k b/d market. These three North American markets total ~1.5-m b/d; of this, perhaps 700-k b/d of market share could be lost by the end of 2013, with exports to PADD III falling to zero, and PADD I and Canada falling by 200-k b/d each. As discussed earlier, rail unloading capacity (Figure 10) on the East Coast is hitting 900-k b/d, and West Coast refiners also appear eager to tap crude-by-rail volumes, with some 500-k b/d of light crude imports, of which 200-k b/d is light, sweet.

Figure 24. US imports of light sweet West African crudes already in secular decline; West African crude imports are now at 0.6-m b/d levels, down from 1.5-m b/d levels seen in 2010 and earlier (m b/d)



Source: EIA, Citi Research

Figure 25. West African crude premia to Brent should be easing structurally over time as US light sweet imports decline, although structural North Sea tightness provides some resilience ($/bbl)

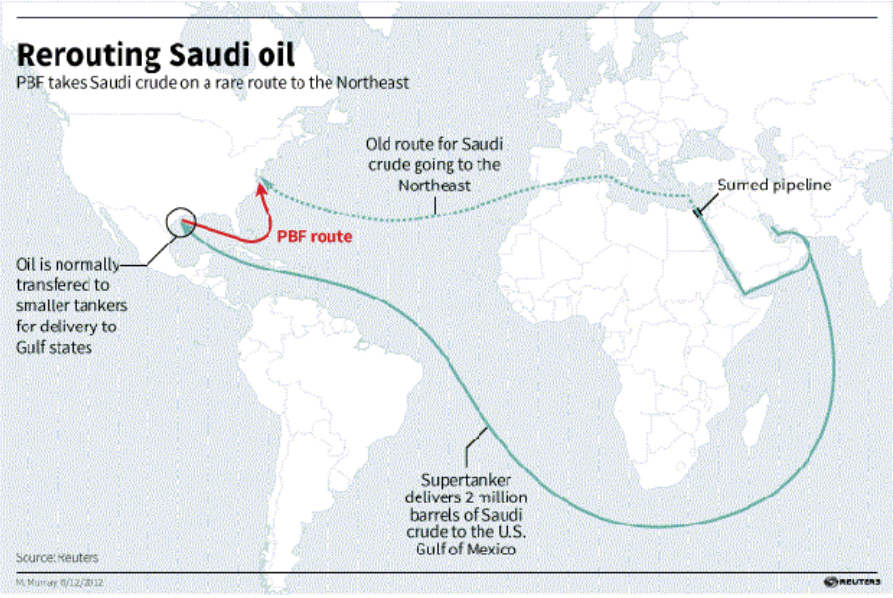


Source: Bloomberg, Citi Research

From the perspective of the Western African producers, this reduces the bid on its crude allowing greater volumes to move east to Asia. The latest November 2012 Energy Information Administration (EIA) data show the US importing 485-k b/d from Nigeria, down from 1-m b/d levels since 2005; these imports represent a quarter of the country's October production of 1.9-m b/d, although Nigeria has seen months of lower production given significant flooding and pipeline theft problems. In the same month, the US imported 145-k b/d from Angola, down from 600-k b/d levels since 2005, or now down to less than 10% of the country's 1.7-m b/d production that month. This is as Angola sees output growth as new offshore fields come online.

Meanwhile, other ways around the limited ability to move crude out of the US midcontinent and Gulf Coast should be increasingly explored. One such scheme was seen in recent reports of rerouting Saudi oil en route to the Gulf Coast by unloading part of its crude ("lightering") while in international waters and sending this to the East Coast.

Figure 26. Lightering in Gulf of Mexico international waters to circumvent the Jones Act



Source: Reuters

Phase II: Canadian WCS and syncrudes reach the Gulf Coast, pushing out Venezuelan, Mexican and Middle Eastern crudes

Soon after the onslaught of light, sweet crude production in 2013, new pipeline capacity by 2014 could enable more than 1-m b/d of mostly sour Canadian crudes to reach the Gulf Coast as well. At more or less the same time, US Gulf of Mexico production should reverse its slide that started in 2010 as the post-Macondo drilling moratorium has ended and new production growth should start in 2013. All of these developments start to challenge suppliers of sour crude to US Gulf Coast markets. Producers with downstream marketing operations in the US should literally find themselves swimming upstream against the tide to preserve market share. These producers include Venezuela, Mexico and the Middle East.

Canadian oil sands production outlook

Canadian oil sands production could grow ~1.9-m b/d to 3.7-m b/d between end-2012 and 2020, or some ~250-k b/d every year. Of this, the majority of the growth looks to be in non-upgraded heavy crude supply, with perhaps 325-k b/d of growth in upgraded light crude to 2020 as a new planned upgrader could be built in 2014 and existing facilities expand (with Suncor's Voyageur upgrader looking like it may be canceled), and plateauing thereafter as little new upgrading capacity is expected to be built going forward.

Given challenging price differentials for WCS and waterborne grades, 2020 oil sands production could range widely, perhaps between 3-m b/d (or +110-k b/d of average growth every year) to over 4-m b/d (or over +240-k b/d of average growth every year), depending on prices, which in turn depend on how much Canadian crude can reach Gulf Coast markets, and importantly, Pacific Basin markets; these factors themselves hinge on pipeline infrastructure and rail build-out. Currently, given significant political obstacles, the risks are for a lower outlook for Canada, contingent on sufficient takeaway capacity south to the Gulf Coast or west to Asia.

Figure 27. Canada oil sands upgrader capacity – current and planned expansions

Upgrader	Capacity		Date
Syncrude	350	-	
Nexen Long Lake	58.5	-	
Suncor Millennium	350	+25	2013
North West Redwater		+50	2016
CNRL Horizon	120	+250	2016
Suncor Voyageur		+250	?

Source: Company reports, Citi Research

Figure 28. Canadian oil sands production outlook (k b/d)

	2012	2013	2014	2015	2016	2017	2018	2019	2020
Athabasca Oil Sands Project	225	255	265	285	305	305	305	305	305
CNRL Kirby	-	-	6	16	34	62	75	85	85
Christina Lake	55	78	113	128	143	163	193	218	233
Cold Lake	150	150	155	165	175	185	190	190	167
Fort Hills	-	-	-	-	-	-	-	-	-
Foster Creek	110	118	122	137	167	205	235	245	245
Great Divide Project	14	18	19	19	19	19	19	19	19
Hangingstone	8	9	10	10	15	25	35	37	37
Horizon	88	106	115	125	152	167	207	238	250
Jackfish	55	60	68	73	80	93	103	105	105
Joslyn	-	-	-	-	-	-	-	-	-
Kai Kos Dehseh	16	19	19	24	34	50	65	80	80
Kearl	-	50	90	130	160	200	235	275	300
Long Lake	34	48	52	60	67	72	85	95	102
MEG Christina Lake	27	32	52	62	69	97	119	147	169
MacKay River	30	30	30	30	35	50	65	70	70
MacKay River (PetroChina)	-	-	9	25	35	45	60	80	100
Narrows Lake	-	-	-	-	5	20	40	60	78
Orion	4	5	5	6	6	6	6	6	6
Peace River	7	8	9	10	13	17	27	37	47
Primary CNRL Cold Flow	24	23	22	21	20	19	18	17	16
Primary CNRL Pelican Lake	45	58	66	74	76	78	78	72	62
Primary Cenovus Pelican Lake	24	28	35	45	55	52	50	47	45
Primary Penn West Seal	4	6	10	12	16	15	13	12	11
Primary Shell Canada Seal	6	7	9	8	7	6	5	4	4
Primrose/Wolf Lake	109	120	120	120	120	120	120	120	120
Suncor Mining Project	283	278	278	278	278	278	278	278	278
Suncor SAGD Project	100	176	187	187	187	187	187	187	187
Sunrise	-	-	5	10	35	45	66	75	106
Surmont	27	27	27	33	52	77	87	110	110
Syncrude Project	364	394	400	405	405	405	405	405	405
Tucker	8	12	17	17	17	17	17	17	17
Total liquids	1817	2115	2315	2515	2782	3080	3388	3636	3759
Year-on-year growth	217	298	200	200	267	298	308	248	123

Source: Wood Mackenzie, company reports, Citi Research

Greenfield expansions start with the ExxonMobil subsidiary Imperial Oil's Kearl project (an oil sands mine about 70km north of Fort McMurray, Alberta), which could start-up in February 2013, perhaps seeing an average of 50-k b/d of new production in 2013. Further new projects include CNRL Kirby and Sunrise, perhaps beginning production in 2014 and Narrows Lake, which could come online in 2016-17. This is joined by expansions of existing projects which have the potential for substantial growth, as long as the economics work. In 2013, Suncor's Firebag Phase 3 project ramp-up should add further growth. The Suncor and Total developments of Fort Hill and Joslyn, however, look severely challenged and are likely to be canceled. With these additions and cancelations, the Canadian production outlook on net remains at over 3.7-m b/d for 2020.

Figure 29. Canadian debottlenecking pipeline projects

	2012	2013	2014	2015	2016	2017
KM Trans Mountain	300	300	300	300	300	890?
Enbridge Northern Gateway	-	-	-	-	-	525?
TransCanada Mainline conversion	-	-	-	-	-	625?
Enbridge Mainline light	1,069	1,069	1,069	1,069	1,069	1,069
Enbridge Mainline heavy	1,246	1,246	1,466	1,466	1,466	1,466
KM Express/Platte to Wood River	280	280	280	280	280	280
TransCanada Keystone to Cushing/Patoka	591	591	591	591	591	591
TransCanada Keystone XL (northern leg)	-	-	-	700?	700?	700?
Enbridge Eastern Access (Lines 9, 6B)	-	-	200	200	200	200
Total	3,486	3,486	3,906	4,606	4,606	6,346

Source: Company reports, Citi Research

But infrastructure bottlenecks remain a challenge to Canadian crude – it simply is struggling to reach markets, leaving WCS and syncrude differentials heavily discounted versus waterborne crudes. This should encourage maximal refinery use where possible, plus infrastructure build-out — and indeed both are happening — but policy obstacles may conspire to prevent this. Ultimately, this is having an effect on producers by eroding their economics and eventually stymieing supply growth. Since the first Energy 2020 report published in March 2012, companies have been pulling back on future production plans in Canada. The latest is Shell who is signaling a pull-back in brownfield expansion of the Athabasca Oil Sands Project (AOSP) due to heavily discounted WCS. Fort Hill and Joslyn could yet be pushed back, with the final investment decision continuing to be deferred. As these projects are at the top end of the cost curve, they are hard to justify unless infrastructure is built (read Keystone XL, and/or the westward pipelines Trans Mountain and Northern Gateway).

Of course, the resources are there, and are massive. Of the remaining established 170 billion bbls of reserves in Alberta (technically recoverable), 135 billion barrels (80%) are recoverable by *in situ* methods, and the other 34 billion barrels (20%) recoverable by mining. Upstream consultancy Woodmac sees remaining commercial 2P reserves (reserves considered likely than not to be recoverable) at 48 billion barrels, out of initial reserves of 55.4 billion barrels. Another 39.9 billion barrels of technical (sub-commercial) reserves could be developed as part of future phases of expansion. Another 57.9 billion barrels of technical resources bring total technically recoverable resources to around 97.8 billion barrels. Woodmac counts another 17.1 billion barrels as undesignated, providing further upside potential into the future.

Over half of bitumen is currently mined, and then is usually upgraded in integrated operations. But the Kearl mining project, which is starting up its first 110-k b/d phase in 1Q'13 (though 2013 may only see an average of ~50-k b/d as it ramps up) does not have an associated upgrader and instead delivers dilbit directly to market, or has some volumes processed by third-party upgraders.

More and more oil sands crude is produced using *in situ*, thermal methods (by cyclic steam stimulation, or CSS, and steam-assisted gravity drainage, or SAGD) with volumes from these means likely to overtake mined bitumen perhaps as soon as 2015. *In situ* bitumen is usually delivered to offsite upgraders, such as at Suncor's integrated mining facilities. We note that Nexen's Long Lake project is the only *in situ* project that has an onsite upgrader.

Given most volumes post the Kearl mining project are *in situ* projects, and *in situ* projects tend not to have upgraders associated with them, expect more dilbit to hit the market, while light upgraded oil sands – syncrude – should see a plateauing trajectory this decade. Plans to build upgraders have been delayed or canceled due to collapsing light-heavy crude differentials, thanks to copious volumes of light sweet shale oil being produced "downstream" of western Canada on its way to the US Gulf Coast. Current planned projects are the North West Upgrading Project (45km northeast of Edmonton), with 50-k b/d of bitumen processing capacity in a first phase planned for 2016, and the Voyageur Upgrader (in Fort McMurray) with 250-k b/d of processing capacity, planned for 2016, with a decision on this project currently due for the end of 1Q'13, though this looks likely to get thrown out. Expansions at CNRL Horizon and Suncor Millennium upgraders could add ~325-k b/d of syncrude production (not counting Voyageur). Utilization rates may in turn be dependent on light-heavy crude differentials, blending costs and pipe/rail transportation tolls.

Rail, again, plays an increasingly important role, due to its flexibility to reach varying destination markets in the interim before pipelines are built. But the specific economics of transporting bitumen by rail also play a role.

Bitumen is heavy and viscous, and requires blending before transporting by pipeline. However, heated rail cars can be used to transport undiluted bitumen, which improves rail economics vis-à-vis pipelines, but makes it more expensive in other ways.

Transporting by pipeline requires blending with either diluent (such as condensates, naphtha and pentanes) or upgraded syncrude. The blending component adds costs of some $3-4/bbl, and further, is more expensive in Alberta than on the US Gulf Coast, since Canada actually needs to import diluents, and could see growing volumes from Eagle Ford production going forward. Further, a barrel of diluted bitumen (or “dilbit”) contains 70% bitumen (as compared with syncrude blended with bitumen, or “synbit”, which contains 50% bitumen), so on a per barrel bitumen basis, this erodes the economics further, such that rail can save another $3-4 per barrel of undiluted bitumen.

This is a $6-8 advantage per barrel of bitumen for rail over pipeline, which has made it economic to rail certain volumes while WCS and syncrude differentials to WTI have remained wide, and WTI-LLS has remained wide.

Sending bitumen by rail also disproportionately frees up pipeline capacity, given the dilution of bitumen; railed volumes back out around 1.5 barrels of corresponding pipeline volumes, helping ease pipeline capacity further.

US Gulf Coast as a "natural" market for Canadian crude

North American refinery configurations have evolved in anticipation of Western hemisphere crude supply becoming heavier over time, with Venezuela and Mexico key drivers of late-last century, and going forward, Canadian oil sands. Particularly on the US Gulf Coast, refining capacity has become well equipped to deal with heavy, sour crudes, while Canada's refineries have remained focused on light, sweet crude processing. Shale oil and syncrude – light, sweet crudes – have turned this picture partly upside down (although syncrudes tend to be blended with conventional crude to optimize gasoline output for catalytic crackers in conventional refineries).

Newly upgraded refineries in the US midcontinent allow the processing of heavier crudes. Light-heavy spreads fluctuating between parity and $7/bbl appears to be the range around which refiner economics could see substitution for light versus heavy crudes and blending in between.

With pipeline and rail capacity growing, the US Gulf Coast could receive up to an additional +600-k b/d more of Canadian crude by 2015-16 (from just over 100-k b/d today, mostly via the Pegasus pipeline from Patoka, IN to Nederland, TX), with the growth coming from increases in Albertan production. Existing production is satisfying some 1.5-1.6-m b/d of heavy demand in PADD II (as of mid-2012 in the latest, but lagging, National Energy Board data) which should have grown perhaps up to 80-k b/d as Marathon Detroit's upgrade project was completed at end-2012, and can grow another +230-k b/d when BP Whiting's new coker is planned to come online in early 2014. It should be accommodated by the diversion of some 785-k b/d of Cushing inflows from the Permian Basin as well as the debottlenecking effects of 1.15-m b/d of new Cushing-to-Gulf Coast capacity on Keystone XL's southern leg (700-k b/d by end-2013) and the twinning of the Seaway pipeline (+450-k b/d to 850-k b/d in 2014). Additional pipeline capacity easing includes Enbridge's Alberta

Clipper pipeline (+120-k b/d to 570-k b/d by mid-2014, from Alberta to Superior, WI) and then along the Southern Access pipeline (+160-k b/d to 560-k b/d by mid-2014, from Superior to Flanagan, IL) followed by Flanagan South (+600-k b/d from Flanagan to Cushing, OK by mid-2014), as well as the northern leg of the Keystone XL pipeline, if approved (+700- to +830-k b/d perhaps by end-2015, between Alberta and Cushing, OK). Rail could transport further volumes out of Western Canada.

Most of the additional volumes should be non-upgraded, WCS-like crude, although some of this could be additional syncrude volumes, which could increase +25-k b/d in 2013 and perhaps +300+k b/d in 2016, if North West Redwater and the CNRL Horizon expansion are completed; more if Voyageur manages to see the light of day, but this looks unlikely. These light, sweet volumes - as crude of foreign (non-US) origin - could be exported from the US Gulf Coast (see the later discussion on crude exports).

Keystone XL (Hardisty, AB to Cushing, OK) could be the limiting factor here. Currently, Canada exports around 2.1-m b/d of crude, mainly to the US. This can travel south along some 3.2-m b/d of pipeline capacity – on the Enbridge Mainline to the Chicago area, as well as TransCanada's Keystone to Cushing/Patoka, and the Express/Platte lines that end up in Wood River/Patoka, IL. Although nameplate capacities exceed crude flows, prices have stayed challenged relative to WTI, at some ~$30 discount; new pipelines south of Cushing should help ease the situation somewhat by allowing greater access to heavy crude conversion refineries on the Gulf Coast, particularly with Keystone XL.

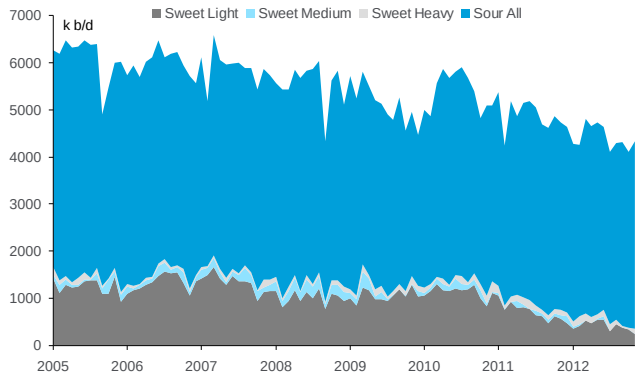
In the short-term, the return to service of BP Whiting's 250-k b/d crude distillation unit (CDU) and associated coker should help boost Canadian heavy demand in the Chicago area, but recent statements suggest the coker will not be ready until early-2014. However, the converted CDU could be ready by July 2013, but take light sweet volumes until the coker comes online. Beyond pipelines, some 200-k b/d of Canadian crude is estimated to travel by rail. PBF Energy, the independent refiner, announced plans to double rail unloading capacity at the 190-k/d Delaware City refinery from 40- to 80-k b/d by end-2013. (The refinery also has 70-k/d of Bakken rail unloading capacity,)

The pipelines going further south should have ample capacity to take these volumes down to the Gulf Coast; the Cushing-to-Gulf Coast leg of Keystone XL (700- to 830-k b/d capacity) should be in place at end-2013 and the twinning of the Seaway pipeline (adding another 450-k b/d) could see the light of day in mid-2014, adding over 1-m b/d of capacity south of Cushing. Rail should take Canadian crude to other markets.

PADD III sour crude imports which stood at 3.6-m b/d levels as of summer 2012, could be hit by the arrival of up to 600-k b/d of Canadian crude, alongside perhaps another +500-k b/d from production growth in offshore US Gulf of Mexico between now and mid-decade and fall close to 2-m b/d levels, although there are risks to the downside.

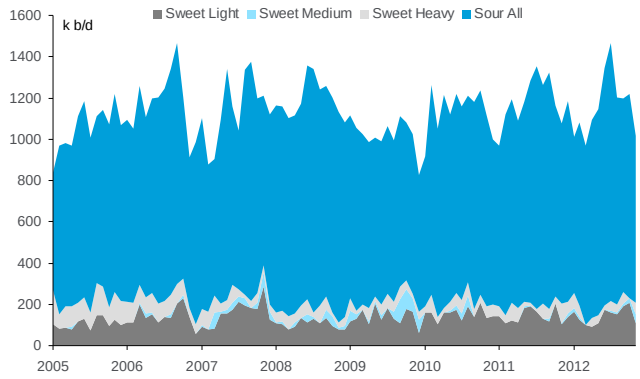
WCS-like crude would cut into Gulf Coast imports (3.6-m b/d sour), competing with Venezuelan, Mexican and Middle Eastern volumes (EIA import numbers), as well as the US's own medium sour production (Mars, Green Canyon and Poseidon).

Figure 30. PADD III sour crude imports at 3.6-m b/d in July 2012, with heavy sour at 2-m b/d (below 27 API)



Source: EIA, Citi Research

Figure 31. PADD V crude imports by quality – sour crudes stood at over 800-k b/d in Nov-12, heavy sour at just over 300-k b/d (below 27 API)



Source: EIA, Citi Research

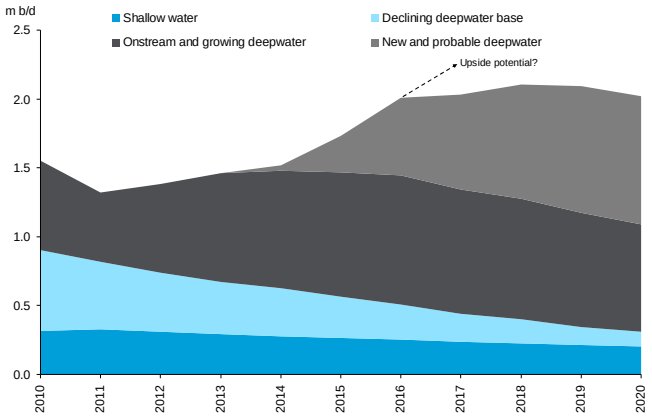
US Gulf of Mexico deepwater production could grow by some 0.5-m b/d toward 2-m b/d by 2016-17 after which there could be further upside potential toward 2020, while Canadian oil sands could see +1.9-m b/d to 3.7-m b/d by 2020; this growth of over +2-m b/d, combined with some heavy-to-light substitution, could push out a chunk of Gulf Coast imports, over time leaving only those volumes from Saudi and Venezuelan term contracts to their downstream refineries. Canadian exports could thus begin to be exported out of the Gulf Coast. But what gives first – the pushing out of all sour imports to US PADD III, or the opening up of a westward outlet for Canadian crudes to reach the Asian market? In all likelihood, given the slow political process in Canada, exports from the US Gulf Coast should come first.

Under the terms of the free trade agreement with Canada, Canadian crude oil entering the US may be exported so long as there is certification of movement across US territory (i.e. swaps are not allowed). Only national oil company (NOC) term relationships would likely remain in the US market, while Canadian crudes could be exported and compete against Urals in Europe, or shipped to Korea to compete with Middle East crudes as part of a potential FTA between Canada and Korea. This would imply a netback to Alberta of Urals minus ~$10 per barrel, broken down into a ~$2 discount to Urals, transatlantic transportation of ~$1, pipeline tariffs of $7-8 in the case of European exports, and the FTA incentive on exports to Korea..

In addition to the Gulf Coast, Canadian oil could displace US West Coast imports too. Railed crude from the Bakken is already reaching the California and Washington State, with anecdotal reports of volumes to Tesoro Anacortes, Washington and Alon Bakersfield, California; light sweet imports in PADD V are around 150-k b/d and are a market for crude-by-rail. Canadian syncrudes could also find access to this markets via rail as well, as could Canadian heavy sour crudes. PADD V's sour crude imports stood at 1.2-m b/d in July 2012 (although at 1-m b/d levels prior to that in the last few years) and could be another market for Canadian sour to push out. Of this 1.2-m b/d, 400-k b/d was heavy sour (the cut off point in this calculation was 27 API; for reference, WCS has an API gravity of 20.3).

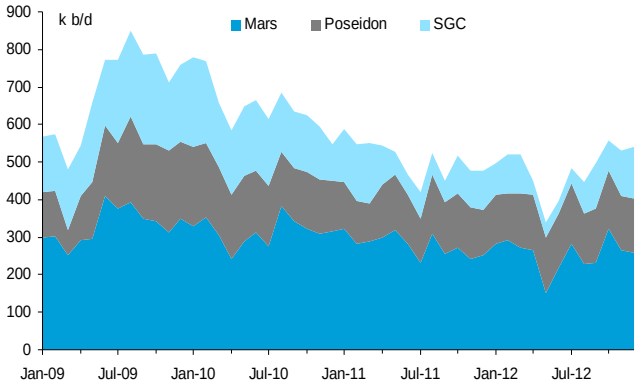
If and when the westward pipelines from Edmonton, Alberta to the Pacific coast of Canada are completed – plans see a target date of 2017-18, but these are likely to be delayed – western Canadian volumes should look to prioritize reaching the lucrative, fast-growing Asian market, which could offer potentially higher netbacks. But that depends on the negotiations across lands controlled by First Nations in Canada and by the Province of British Columbia.

Figure 32. Deepwater Gulf of Mexico total liquids production could grow to 2-m b/d by 2016-17, with upside and downside risks to 2020



Source: Wood Mackenzie, Citi Research

Figure 33. US Gulf of Mexico medium sour crude production rebounded after maintenance and weather-issues over summer 2012

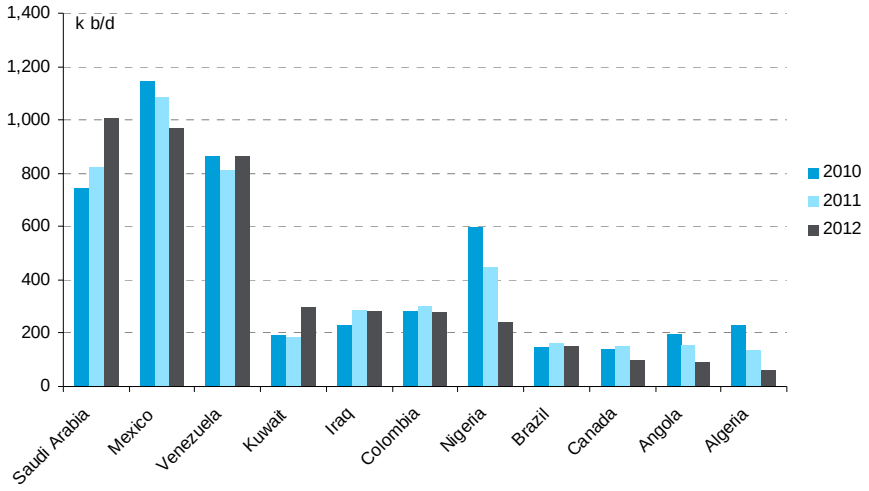


Source: Company websites, Citi Research

Middle East, Venezuela and Mexico feel the squeeze next

The outlook for medium and heavy crudes in the US Gulf of Mexico is dour, hit on three sides by easing Brent prices, a blowout of the Brent-LLS spread as light, sweet crude floods the Gulf Coast, and then the arrival of Canadian sours. These erode import markets for light sweet, as described in *Phase I*, but then also heavy crude markets. These are represented by some of the largest suppliers of medium and heavy crudes currently to the Gulf Coast (PADD III) region: Venezuela, Mexico, Saudi Arabia and other Middle Eastern producers.

Figure 34. Largest imports by country into the US Gulf Coast (PADD III), 2010-12



Source: EIA, Citi Research

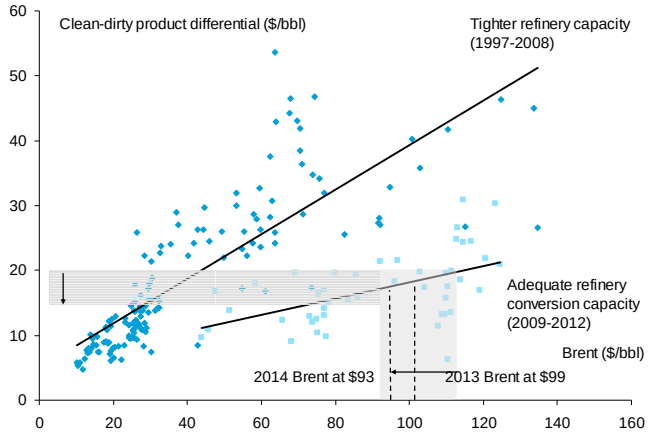
As discussed earlier, 2013 sees 1.6-m b/d of incremental pipeline capacity debottlenecking Cushing and moving to the US Gulf Coast. Much of this could be Canadian heavy sour. Jan-Apr 2013 could see ~500-k b/d of pipeline capacity additions, with the rest by end-2013. All light, sweet imports could be pushed out of the USGC, while increasing volumes by rail eat into East and West Coast imports. LLS-Brent should blow out due to the glut of LLS with nowhere to take all this crude quickly plus LLS in contango. LLS could be $2-5 below Brent, or further, depending on US crude exports and potential waivers to the Jones Act.

Mars crude is a blend of crude oil from three platforms in the Gulf of Mexico while Maya is a blend of crude oil from Mexico

2013 Mars crude price could move down to the $89-94 range, while Maya crude price could move down to the $83-89 range, both hit mainly by the change in the LLS-Brent spread. Lower Brent prices, more heavy refining conversion capacity from Motiva Port Arthur and later from BP Whiting, and higher light product yield from more shale oil in the crude slate combine to narrow clean-dirty product and light-heavy crude spreads, helping to modestly offset the hit from Brent and LLS. Brent could ease to $95-105, pushing Brent-LLS toward the wider end of $2-5, LLS-Mars at $3-4 and LLS-Maya at $8-12.

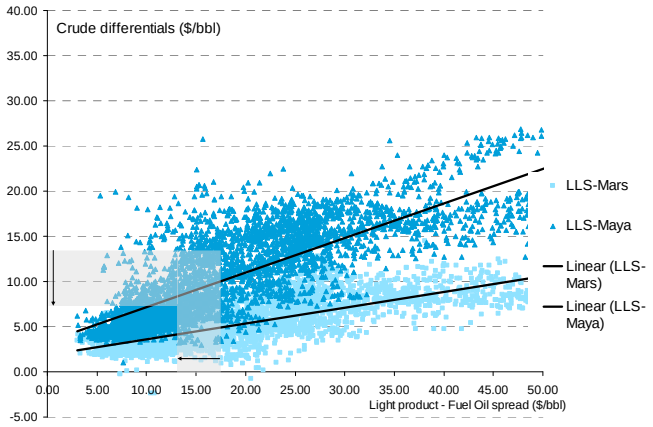
But in 2014, more Canadian volumes hit the US Gulf Coast. The southern leg of Keystone XL should ramp-up and could be bringing 500-k b/d of Canadian sour to the Gulf. The doubling of Seaway in 2014 could bring more light sweet as well as Canadian sour to the Gulf. LLS could face even more pressure without adequate outlets. Mars/Maya should see pressure from increased Canadian volumes by pipeline, but also by rail. And both Mexico and the US Gulf of Mexico could see modest crude production growth.

Figure 35. Clean-dirty (USGC gasoline vs HSFO shown here) product differentials should narrow with weak local light product demand and more ample refinery conversion capacity in 2014-15, but the 2015 ECA 0.1% sulfur limit should pressure HSFO, widening the spread



Source: Bloomberg, Citi Research

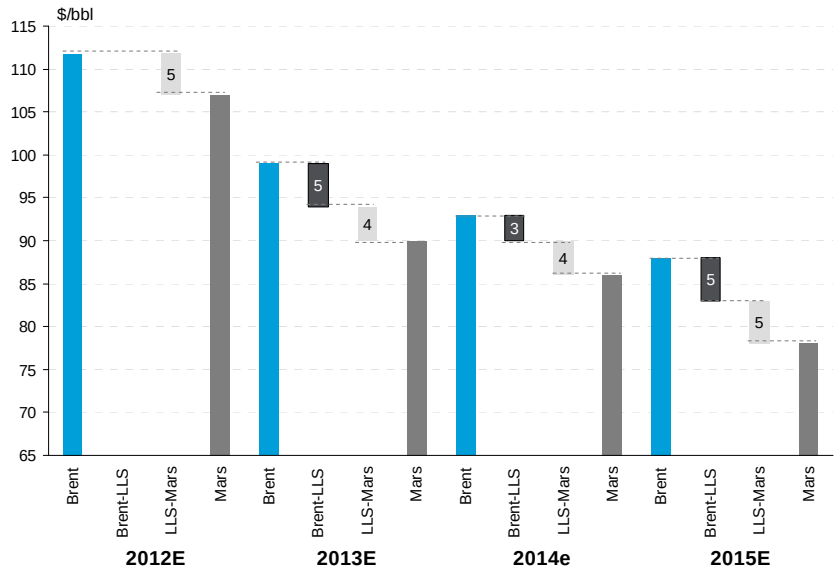
Figure 36. LLS-Mars and LLS-Maya could see a narrowing first as the glut of light sweet challenges LLS, and light product-fuel oil differentials narrow, before widening as Canadian volumes reach the Gulf Coast even as US Gulf of Mexico and Mexican production grows



Source: Bloomberg, Citi Research

By 2014 Mars could move down to the $82-87 range, while Maya could be in the $75-82 range, hit by Canadian volumes to the USGC. With Brent likely averaging $93 (see later on the broader outlook on long-term Brent prices), Brent-LLS on the wider end of the $2-5 range or higher, and LLS-Maya facing widening pressures from growing Canadian volumes is also expected to be on the wider end of the $8-15 range. January 1, 2015 sees the 0.1% sulfur limit hit fuel oil, weakening Maya further into 2015, perhaps to $68 or lower; 2015 could see the northern leg of Keystone XL pipeline add further pressure from Canadian volumes. From 2015 onward, growing light sweet and medium/heavy volumes will keep the pressure on US Gulf of Mexico sours.

Figure 37. Brent, LLS and Mars price outlook 2012-15E ($/bbl)



Source: Citi Research

As light-heavy spreads compress, the incentives for light-heavy switching increase – $4-7 levels have been a "floor" level in the past – further pressure could see idling of cokers and some push-out of medium and heavy crude imports, weakening Mars/Maya even as LLS falls, to keep the spread from narrowing too far for extended periods. More volumes could be sent up Capline.

There are further risks to the downside. Venezuela post-Chavez remains a major tail risk. Venezuelan production could see significant new growth if its various Junin and Carabobo upstream projects start to bear fruit; timing remains a question, but post-Chavez could see a more conducive policy environment. Meanwhile, Colombia's Rubiales crude output also continues to rise and recent shale discoveries in that country could be another huge supply surprise in the next five years. These supply increases could happen even as US import markets shrink, depressing prices.

And fuel oil – closely linked to heavier crude values – could be hit by tightening sulfur standards for marine use. Under Annex VI, the North American Emission Control Area (ECA) became enforceable on August 1, 2012, limiting sulfur in fuel oil to 10,000 ppm (1%). The next phase comes January 1, 2015, limiting sulfur in fuel oil to 1,000 ppm (0.1%). As switching occurs away from high-sulfur fuel oil (HSFO) to low sulfur fuel oil (LSFO) or low sulfur diesel, this depresses heavy crudes, including those in the US Gulf of Mexico.

On the upside, there is talk of the Hovensa St. Croix refinery potentially coming back, as its economics may yet make sense. And any easing of the Jones Act, or greater volumes to Canada, could help support crude values on the Gulf Coast.

Phase III: Canadian crudes face-off with Russian ESPO for the Pacific Basin market

Fast forward to 2017-18 and the completion of two major westward Canadian pipelines and Canada looks poised to take over as benchmark for the Pacific Basin market. The two planned pipelines are expected to provide a combined incremental addition of 975-k b/d of capacity. Kinder Morgan's Trans Mountain expansion would add 450-k b/d of capacity to its existing 300-k b/d to reach 750-k b/d between Edmonton, Alberta and Burnaby, British Columbia. The existing capacity sees around 250-k b/d allocated to British Columbia as well as Washington state refineries in the US, and around 80-k b/d allocated to shippers at the coastal dock of Westridge. Enbridge's Northern Gateway would be an entirely new line with 525-k b/d of capacity, but which could ramp-up to 830-k b/d, from Bruderheim close to Edmonton, Alberta, to Kitimat, British Columbia. There are, however, risks these projects being completed. Enbridge, in particular, has been criticized for its environmental record. These involved leaks from its mainline system in the US over recent summers, and previous accidents elsewhere.

With a Pacific Basin option, Western Canadian crudes could be sold spot, free-on-board (fob) from the Canada west coast. The huge volume contract sellers from the Middle East and West Africa would continue, but the main rival for spot volumes would be from Russian ESPO. Canadian crudes could have widespread attraction in the Pacific market and would largely be sold spot, with significant competition as large spot crude in the Pacific Basin only from Russia.

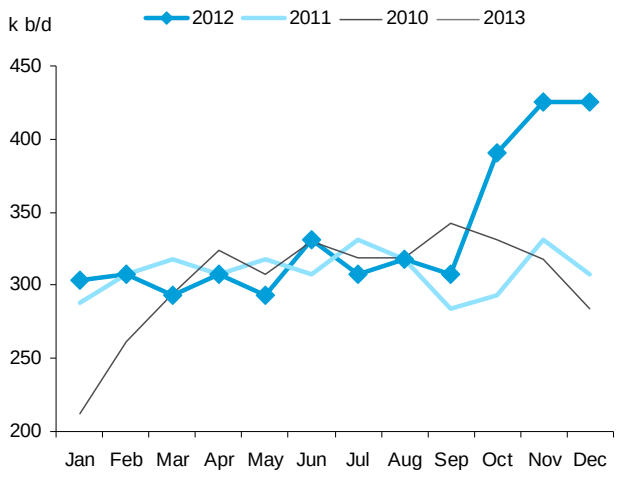
Russia's ESPO line and its consequences

The East Siberia - Pacific Ocean (ESPO) line is a strategic pipeline for Russia, allowing it to diversify its markets away from a currently stagnant Europe, while laying the ground for potentially establishing a Russian pricing benchmark in fast-growing Asia, a core area of global oil demand growth going forward. The first phase of the ESPO pipeline only stretched from Taishet in Eastern Siberia eastwards to Skovorodino, with rail taking volumes further east to the port of Kozmino. A pipeline spur was completed to Daqing, China by end-2010, and now the second phase of ESPO, the pipeline connecting Skovorodino all the way to Kozmino, is complete, having undergone testing and initial pipe fill. This has allowed ESPO exports via Kozmino to rise from 300-k b/d levels to over 424-k b/d at end-2012, which is also the planned level for 2013, though this remains below the full capacity that should ultimately be available. To reach 600-k b/d, sufficient Eastern Siberian production would need to be developed to boost ESPO volumes. Later nameplate capacity expansions are expected to rise to 1-m b/d, and later 1.6-m b/d. Combined with the startup of the Baltic Pipeline System-2, Russia has spare pipeline capacity and the option to send crude to Europe or Asia.

Taftneft is a Russian state-controlled business responsible for national pipelines — 93% of the oil produced in Russia is transported on Taftneft pipeline

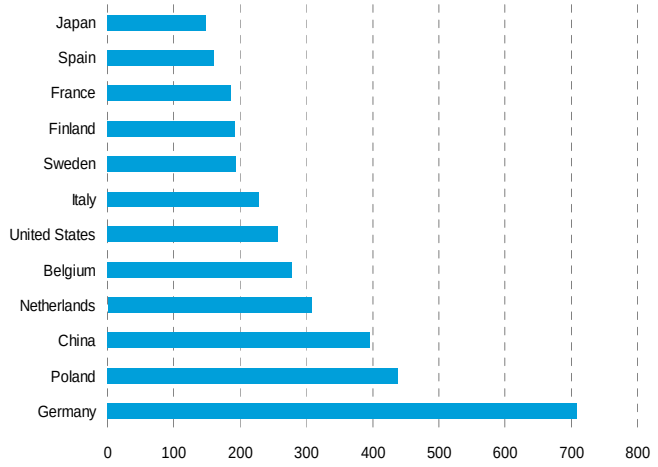
Russia is currently a large but lumpy supplier of oil and gas to Europe, producing ~10.6-m b/d of oil and exporting around 6-m b/d – more than Saudi Arabia until the post Libyan ramp-up on both metrics. Much of this is transported via the pipeline system, mostly dominated by Transneft except for the Caspian Pipeline Consortium (CPC) pipeline to the Black Sea. Pipelines carry oil directly to European markets (via the Druzhba line) or to ports in the Baltic and Black Sea or the Arctic, to be transported onwards to Europe and the US. The ESPO pipeline now allows pipeline volumes to go east towards the port of Kozmino, where ESPO crude and local far eastern Sakhalin production can be shipped to Asian buyers. Rail exports account for around 5% of Russia's oil exports and travel via Estonia and Latvia, as well as eastwards to northeast and central China.

Figure 38. Russian Kozmino ESPO export loading programs up to 424-k b/d in December



Source: Bloomberg, Citi Research

Figure 39. Top importers of Russian crude oil in 2011 (k b/d)



Source: IEA, Citi Research

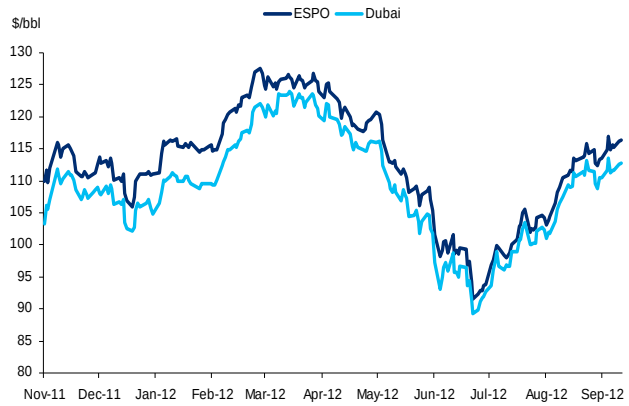
Strategic considerations are at the core of the design of ESPO, outside of the diversification of destination markets away from Europe. Its origin begins in the Eastern Siberia region which is home to significant hydrocarbon resources but very sparse population, positioning it well to be a growing exporter. Meanwhile, China is a key destination market, but the route of ESPO ends at the Pacific port of Kozmino, with a spur to Daqing; the line to the Pacific is critical for establishing fair market value so as to allow Russia not to be beholden to large Chinese buyers at the end of a long pipeline. Kozmino can handle 150-kt tankers, enough for Aframax and Suezmax class vessels.

Figure 40. Map of selected major Russian westward and eastward oil pipelines and transport tariffs

Source: Wood Mackenzie

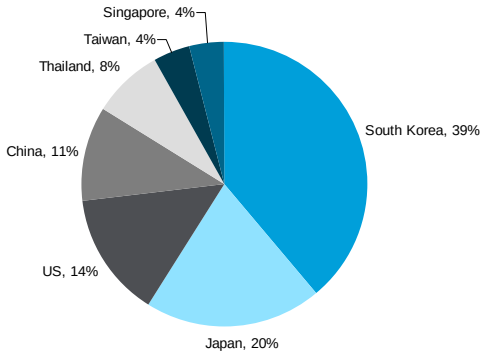
ESPO crude (34.8° API gravity, 0.62% sulfur) is similar to major medium crudes processed in Asia and the US West Coast, such as Oman, Dubai, Arab Light, Basrah Light. These crudes are distillate rich, medium light and relatively sweet, with yields similar to Alaska North Slope (ANS): diesel/gasoil at >20%, jet/kero at >13%, with a healthy naphtha/gasoline cut. And performance to date shows it has not only been able to secure a foothold, but is mainstreaming. ESPO crude started at a discount to Dubai but moved quickly to a consistent premium by mid-2010 as would be expected given quality and distance advantage. As the largest spot crude available in the Pacific Basin, ESPO is now effectively the new benchmark against which Middle East crudes are priced.

Figure 41. ESPO has mainstreamed, now at a consistent premium to Dubai



Source: Platts, Citi Research

Figure 42. ESPO crude by destination



Source: Platts, Citi Research

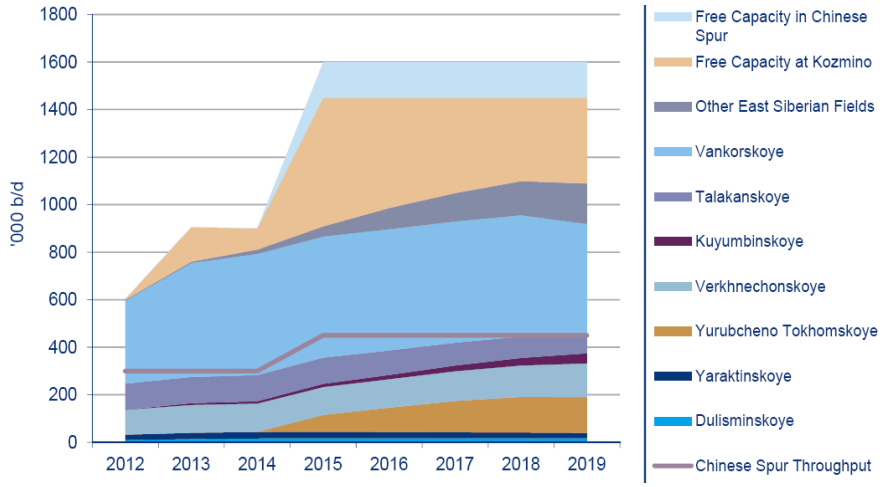
What is missing for a complete transition for ESPO to become a purer benchmark is a formal traded contract on an exchange, and the Russian government has been pushing at least rhetorically for a new contract to be traded on the St. Petersburg Exchange.

The characteristics of a successful benchmark are: a relatively high volume of production, security of supply, consistent quality, and a diversity of buyers and sellers such that any single player does not have too much market power. Russian ESPO should enjoy stable and growing volumes – not including 20-year contracted volumes to Daqing in China, ESPO shipments should be over 420-k b/d, and planned to rise to 482- to 500-k b/d in 2014, and 600-k b/d in 2015. Parallel shipments by rail along the ESPO Phase 2 (Skovorodino to Kozmino) should remain at 60-80-k b/d levels. There are also two refineries that should begin to take ESPO volumes in 2014-15 — Alliance Oil's Khabarovsk refinery and Rosneft's Komsomolsk refinery.

Sufficient Eastern Siberian production is needed to maintain export volumes going forward, which has required supportive tax incentives to assure continued development. Rosneft's Yurbcheno-Tokhomskoye, as well as the Kuyumbinskoye deposit and Messoyakha fields in the Yamal-Nenets region – the latter two of are operated by Slavneft (a Gazprom Neft and TNK-BP JV) – are hoped to provide new volumes alongside current East Siberian production, to allow ESPO volumes to grow.

Crude quality is expected to stay relatively stable, with perhaps small fluctuations. Production growth from the Vankor field (from 357-k b/d in 2012 to 502-k b/d in 2013) could lower ESPO quality somewhat, as could sour volumes from new flows via a Taas-Yuruakh region producer starting in 2015-16, but Gazprom Neft production from East Siberia (a planned 100- to 140-k b/d starting in 2016) could offset this.

Figure 43. ESPO capacity should be well over crude production volumes



Source: Wood Mackenzie

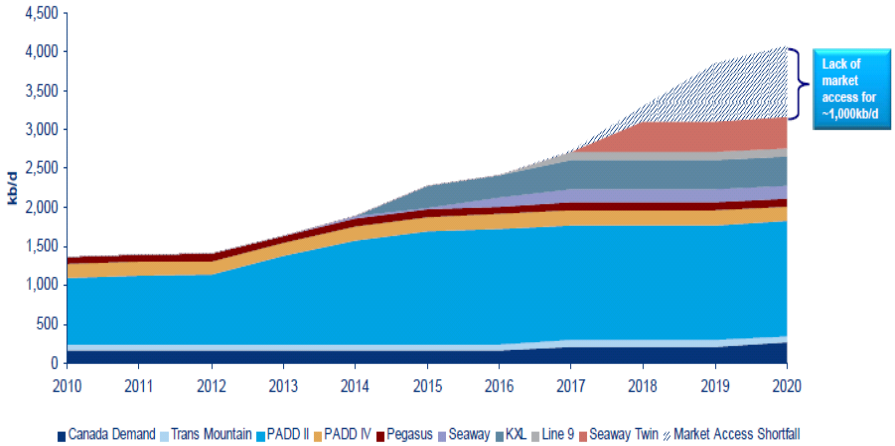
The ESPO pipeline has plans to expand further towards 2015, bringing its waterborne export capacity to 1-m b/d. Eastern Siberian production may not be able to grow to this level until the 2025 timeframe. However, West Siberian producers could direct volumes to the east, as ESPO charges an attractive flat rate network tariff as opposed to the usual tariff formula calculated on a per kilometer basis, which effectively monopolizes control over Europe-bound pipelines, as well as higher sales prices and no additional taxes, relative to Urals NWE. (Urals Med is not a major outlet for West Siberia, generally more attractive for Volga-Urals producers.) Of these Western Siberian fields, Vankor field production could grow rapidly at first but then plateau at ~500-k b/d from 2014 onwards, leaving spare capacity on ESPO perhaps to the tune of 300-k b/d in the latter half of this decade.

Canada steps up to compete for the Pacific Basin

Canada could also fulfill the criteria to be a successful regional crude benchmark – and without government support, to boot. Canadian volumes — once the incremental +975-k b/d brings westward pipeline capacity to 1.275-m b/d to the Pacific Coast — could become a better base-load market for Asia and is more likely to be exchange-tradable, although some of this capacity could still be used for local British Columbia and Washington state refiners. This ~1-m b/d of availability could be mostly syncrude, and some WCS. And the rail network of both Canadian Pacific and CN Rail run to these destinations; with crude oil-capable rail receiving facilities, further volumes could be evacuated via the west coast of Canada.

Without these outlets, significant quantities Canadian heavy could be stranded, depressing prices and eroding production economics until some volumes are shut-in; a projection of the potential disposition of western Canadian heavy (including oil sands and conventional heavy) sees as much as a 1-m b/d shortfall by end-2020, without the Northern Gateway, Trans Mountain pipeline expansion, and rail.

Figure 44. Future potential western Canada heavy crude oil disposition without Northern Gateway, Trans Mountain expansion, rail



Source: Wood Mackenzie

ESPO, WCS or syncrude's appeal as a benchmark would also depend on evolving refinery configurations in Asia. ESPO can make it now as a relatively light, sweet crude. WCS can make it on the US Gulf Coast, which has sophisticated refineries able to handle heavy crudes, but would tend to be ill-suited in Japanese refineries. Syncrude requires blending and catalytic cracking to optimize its output, and is light and sweet. The question is whether China, India and other new refining capacity in Asia will build out ample coking capacity to provide competitive bidding for WCS. Current plans for refinery capacity additions see significant crude distillation capacity build out in Asia – adding around 1-m b/d in both 2012 and 2013 alone – but coking capacity sees no growth after 64-k b/d of additions in 2012, until a planned 10-k b/d addition in 2015. Instead, new capacity is concentrated in hydrocracking and catalytic cracking. These developments suggest syncrude could be suitable in new Asian refining capacity.

This scenario also hinges on the completion of the Kinder Morgan and Enbridge westward pipelines, which still face political opposition from environmental and First Nation groups. These political obstacles were discussed in the first "Citi GPS Energy 2020" report, from page 63.

But if this scenario does come to pass, as economic logic suggests, there would be another transformation ahead in the physical markets: Middle East crude to the Pacific Basin should end up being priced off Pacific benchmarks – not Oman or Dubai. This would cause premia provided to Middle East producers based on the Oman/Dubai benchmark to decline by some $1 to $2 per barrel. This is similar to the lost premia for West African crude now developing in the Atlantic Basin markets. With 17-m b/d of Middle East crude flowing east (without considering increased volumes), the lost revenues could amount to as much as $13 billion.

Where oil meets water: how much and what kind of US crude exports are allowed?

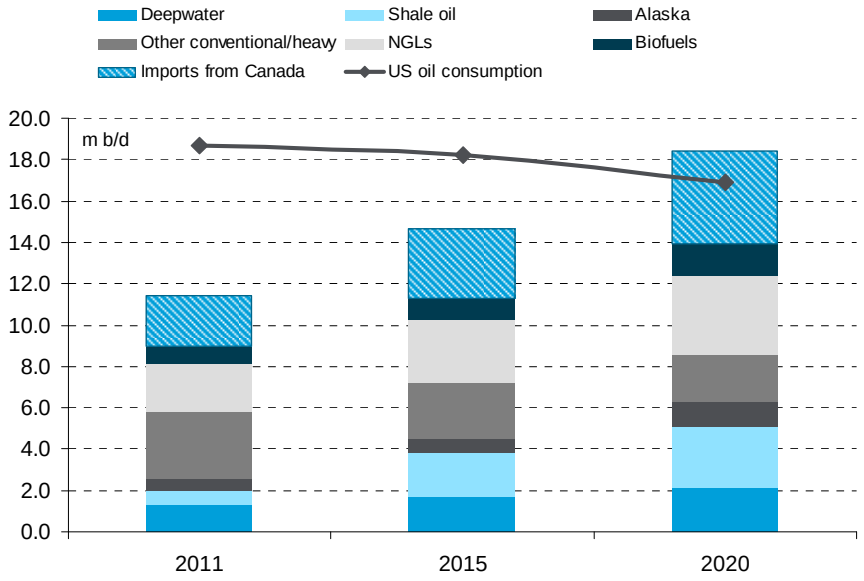
As crude imports get pushed out of the Gulf Coast – first light sweet, then heavy sour – relevant US crude prices should move to a discount to waterborne crudes, notably Brent. This would incentivize exports, but quantities would be limited by US export control rules. Some types of exports are permitted, and already happening, with licenses issued; other cases may need new rules written for them. Understanding export controls is thus the key to understanding how future trade flows – and price differentials – should behave in the future, as well as the key to the future role of the United States in global markets.

The current export control regime dates back to the 1970s in the wake of the Arab oil embargo, which required the President to restrict exports of US-produced crude. Up until 1970-71, US trade controls were on imports, designed to protect US independent producers from competition from lower cost imports. The new mindset was of "short supply", as some of the relevant rules are dubbed. But this is now anachronistic given the emergence of a crude glut within North America, and given the US – including Canadian supply – could even move to a surplus by 2020.

The relevant laws and regulations that cover the licensing of crude exports are the Energy Policy and Conservation Act of 1975 (EPCA), the Export Administration Act of 1979 (EAA), the so-called "short supply" controls in the Export Administration Regulations (EAR), the Mineral Leasing Act (MLA), the Outer Continental Shelf Lands Act (OCSLA), the Naval Petroleum Reserves Production Act (NPRPA), the Trans Alaska Pipeline Authorization Act (TAPAA) and PL 104-58 "Exports of Alaskan North Slope Oil". The entity that regulates crude oil exports and may issue export licenses is the Bureau of Industry and Security (BIS) at the US Department of Commerce. In certain cases, the BIS requires the President to approve crude exports, under a finding that these would be in the US national interest.

Generally, crude oil exports are restricted by statute under the EPCA, while additional restrictions include export of crude: oil transported on Federal right-of-way pipelines, under the MLA; produced offshore on the outer continental shelf, under the OCSLA; and produced from the Naval Petroleum Reserve, under the NPRPA. Crude oil exports are permitted under certain specific cases: crude oil of foreign origin may be re-exported, crude shipped on the Trans-Alaska Pipeline may be exported, and Strategic Petroleum Reserve (SPR) crude may be exported but only if it directly results in import of refined petroleum products that would not otherwise be available.

Figure 45. Crude supply to the US from domestic sources and Canadian imports to the US, versus US oil consumption; by 2020, there could be a surplus of over 1-m b/d available for export



Source: Citi Research

Figure 46. Countries with which the US has free trade agreements (FTAs)

Australia
Bahrain
Canada
Chile
Colombia
Costa Rica
Dominican Republic
El Salvador
Guatemala
Honduras
Israel
Jordan
Korea
Mexico
Morocco
Nicaragua
Oman
Panama
Peru
Singapore

Source: US Trade Representative

Crude oil exports can be issued licenses under the following cases:

- **Exports to Canada, not for re-export as crude**, although it may be refined and exported as products. This is already happening, amounting at end-2012 to some 60-k b/d of export volume, with several new licenses having been applied for by BP, Statoil, Shell, Vitol and others. This rule could potentially extend to other free trade agreement countries, such as South Korea. The US has free trade agreements with 20 countries.

- **Crude oil of foreign origin, with no commingling with oil of US origin**, although the commingling requirement is not unrealistically stringent; foreign oil may be stored in tanks or transported on pipelines that may have once held oil of US origin in them, resulting in trace amounts of commingling. Given more stringent restrictions on export of oil of domestic origin other than to Canada for now, this would be a major alternative outlet for crude exports, especially as pipelines are built out to connect western Canada down to the US Gulf Coast, via Cushing, as well as via rail.

- **Other niche cases:** exports from Alaska's Cook Inlet (unless crude is transported via Federal right-of-way pipeline, under MLA or TAPAA); exports of no more than 25-k b/d of California heavy crude of <20°; exchange of SPR oil for crude or refined products that are needed and not otherwise available; and exports consistent with international agreements which cover situations of international oil supply disruptions, where the President may take action to export oil.

Crude exports for the following cases would require Presidential findings:

- **Under the MLA, crude of US origin transported on Federal right-of-way pipelines** – which is most US-produced crude - may not be exported unless the President finds that the exports do not diminish the availability to the US, are in the national interest, and are in line with the EAA. Crude of US origin transported by other means – such as via rail – are not currently covered by a relevant rule; licenses may only be issued under a relevant rule, so a new rule would have to be written; this process goes through inter-agency review.

- **Under the OCSLA, crude oil produced on the outer continental shelf may not be exported** unless the President finds that exports would not increase dependence on imported oil or gas, are in the national interest, and are in line with the EAA.
- **Under the NPRPA, crude oil from the Naval Petroleum Reserve** may not be exported unless the President finds that exports would not increase dependence on imported oil or gas, are in the national interest, and are in line with the EAA.

Crude exports are allowed without license for:

- **Alaska North Slope crude oil** (under PL 104-58), but this is a limited volume that is shrinking; Alaska oil production as a whole is around 400-k b/d and declining, although there could be growth to 2020 – see *Energy 2020*.
- **The following niche cases:** crude of foreign origin in the SPR (under the EAR); and crude shipped via the Trans Alaska Pipeline System (TAPS) may be exported, with several conditions, including a Jones Act-like rule that the exporting vessel be documented under US laws and owned by a US citizen.

Presidential findings have been made before in situations of local oil surpluses, although in a very limited fashion – Reagan made Presidential findings in 1985 that permitted exports to Canada and out of Alaska's Cook Inlet, and again in 1988 for exports to Canada. President Bush, in 1992, approved the California heavy crude export rule, since state environmental laws reduced demand for such heavy crude, although volumes are very limited, as described earlier.

There have been verbal indications from government sources that condensates above 50° API may be treated as product rather than crude, and thus be exportable without seeking a license, but a specific case is yet to be seen. Otherwise, the definition of crude includes condensate "…produced from tar sands, gilsonite, and oil shale…" – oil shale indicating kerogen rather than light, tight oil – which could suggest that condensates produced from other sources, such as shale (not kerogen), do not require license by the BIS. But ultimately, it will be companies applying for licenses that provide test cases for the implementation of this language.

Going forward, as in the first and second Phases outlined earlier, it looks like exports to Canada could quadruple from 60-k b/d levels in late 2012 to 200-k b/d or more. These would be via pipeline, rail and tanker (non Jones Act vessels). Eastern Canadian imports of light, sweet crude are currently at 500-k b/d levels, mostly from West Africa, and these could be progressively pushed out by North American supply. BP, Statoil, Shell and Vitol look like they have obtained additional licenses for these purposes, with most shipped out of the Gulf Coast, and Statoil transporting Bakken by rail, to the Irving Saint John refinery in New Brunswick, Canada.

Exports to Canada could be a precursor to US exports elsewhere. Given the strong political opposition latent in the US to crude oil exports, flows are likely to be incremental, although the snowballing future of exports to Canada should make a very big difference. Among the other FTA partners of the US is Korea, a 2.4-m b/d market for oil. Korea is also an FTA partner of the European Union. Unlike the US and many other countries, the Republic of Korea puts a tariff on crude oil imports amounting to 3% by value. But importers are exempt from the tariff from FTA partners. Given the combination of transportation economics and the incentives to import oil from an FTA partner, imports into Korea have mushroomed since the FTA with the European Union was implemented in the second half of 2011. A 2-m bbl VLCC of North Sea crude, worth about $230-million at recent prices, provides a $6.9-million incentive to import on a tariff-free basis. Hence, through 2012, Korea's imports increased from nothing to over 200-k b/d, placing upward stress on Brent prices.

As noted, by 2014 there should be growing excess volumes of crude oil available on the US Gulf Coast, both light, sweet grades and heavier more sour grades. By 2015 the now delayed expansion of the Panama Canal should be completed paving the way for exports of crude oil from the US Gulf Coast to Korea, assuming that the same FTA licenses now available for US exports to Canada will also be available for exports to Korea, and if not US crude, then Canadian crude, pending the completion of current negotiations for an FTA between Korea and Canada.

As Canadian crude is able to make its way down to the US Gulf Coast (but before a westward outlet is found to the Pacific Coast), it should as noted, also be exported and begin competing with Urals in Europe or with Middle East crudes in the Far East. Canadian producers would be able to receive some price netted back to Alberta, perhaps Urals minus ~$10. However, after the westward Canadian pipelines are built, oil sands producers could likely obtain higher netbacks by exporting to Asia, easing the need to export from the US Gulf Coast.

Changes in crude export rules could be in store. Though the Obama administration has yet to address the crude exports issue officially, the appointed head of the EIA, Adam Sieminski, has said publicly that crude exports could be beneficial to the US. The political discussion is likely to be charged, with environmental interests against "dirty" exports, industry interests from sectors that benefit from depressed US oil prices such as refiners, but also US oil producers whose economics could be eroded further if stringent export controls lead to a even greater glut at the water's edge. And the director of the IEA recently issued an op-ed in the Financial Times calling for US exports of crude, without which producers would see their economics eroded quickly ("Great US oil boom risks going bust", Maria van der Hoeven in the Financial Times, 6 February 2013).

The related issue of the Jones Act was discussed in Citi's 7 November 2012 report Obama's Victory and Commodities:

"The 92-year-old cabotage law of the United States is under review and it is probably the case that a Democratic President finds it far easier to lead the charge against it than a Republican. Already President Obama has twice granted blanket waivers of the requirement that inter-coastal trade use US flag vessels – currently in dealing with gasoline shortages caused by Hurricane Sandy and 18 months ago as part of the release of strategic stocks triggered by the Libyan disruption. Even if US flag vessels were available, estimates are that it could cost as much as $8 per barrel (~20¢ per gallon) to move gasoline from the US Gulf Coast to the US East Coast. Similarly it costs much more to move the growing abundance of US production of light sweet crude from the US Gulf Coast, where it is about to become surplus, to oil-short refiners on the East and West Coasts than it does to export on non-Jones Act vessels elsewhere."

"The last time the US faced a regional crude oil glut – from Alaska – the cabotage law required oil from Alaska to move to the US Gulf Coast through the Panama Canal at considerable cost. Rather than amend or change the Jones Act, Congress in 1990 amended legal restrictions on oil exports — a law also signed by Democratic President Bill Clinton."

"The Jones Act was designed to protect American shipping and ship-building and the American Merchant Marine and Maritime Unions. It worked well when the US had the strongest shipbuilding industry and the strongest Merchant Marine. Today, the main reason no US flag vessels are hijacked offshore Somalia is that there are basically no US flag vessels. Perhaps this law too will pass."

There was at the time of this writing a review of the Jones Act under way by the US General Accounting Office (GAO). It was specifically looking at the impact of the Jones Act on Puerto Rico, but its findings should be applicable to the US mainland as well. That is likely to be one factor undermining the law, which is designed to protect the US shipbuilding industry for national security reasons. Another factor could be the growing gasoline short position of the US Atlantic coastal region and the favorable economics for consumers of moving crude and gasoline to the US Gulf Coast without the requirements of the Jones Act. But clearly, the structure of both regional and Atlantic Basin crude and product trade are in the balance so long as the Jones Act remains intact.

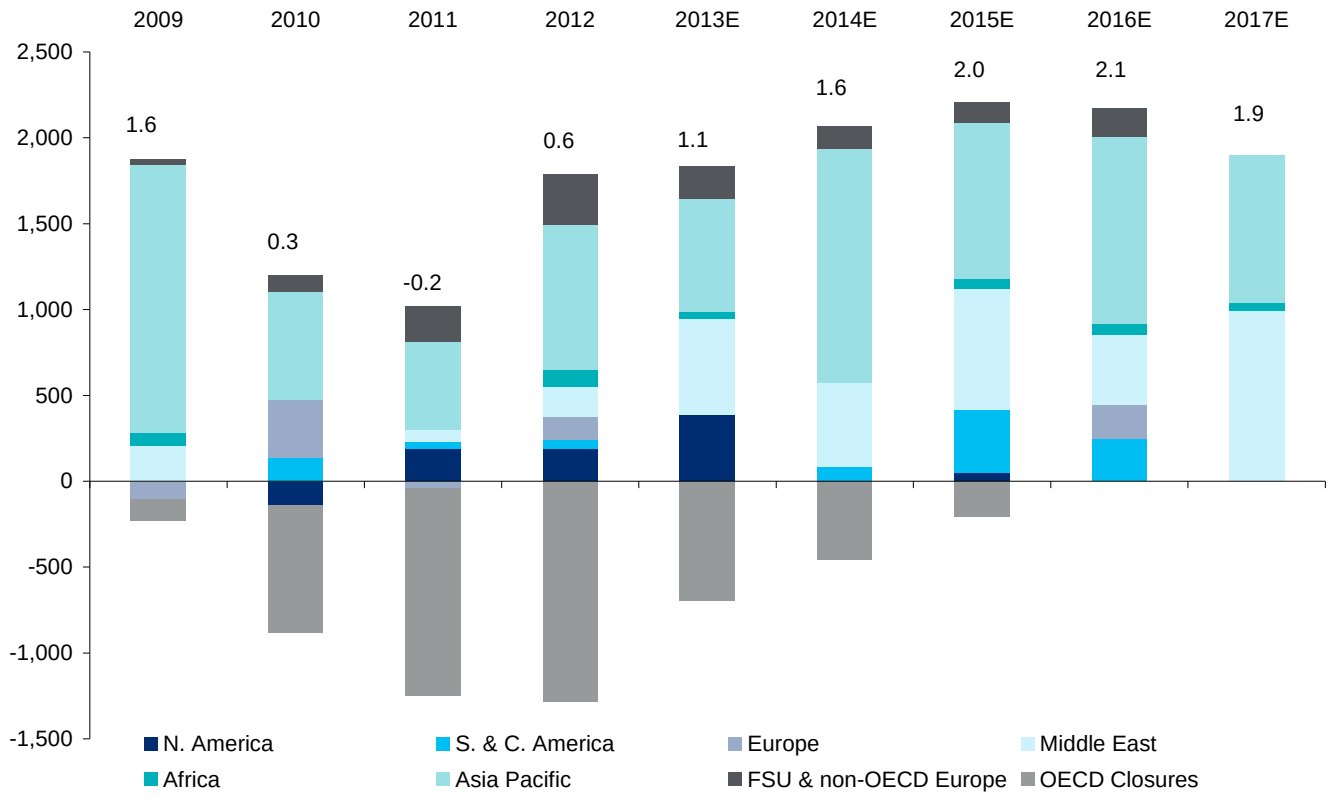
US refining outlook in global context

The emergence of the North American hydrocarbon cornucopia is also coming at a time of shifting demand patterns, between major world regions and different final refined products, due to economic growth, demographic changes, policy factors, and technological innovation. These shifts have been anticipated – correctly or otherwise – by refiners, which have sought to build out crude distillation capacity close to fast-growing markets, as well as conversion units to produce greater yields of higher value gasoline and in particular, diesel/gasoil, and handle lighter or heavier crude feedstock.

Global oil demand growth has become a two-tier phenomenon. In the developed OECD economies, oil demand looks to have peaked, or be plateauing. Transportation fuels, gasoline in particular, are seeing structural declines due to fuel efficiency. Ageing populations and changing lifestyles are leading to lower vehicle ownership per household and fewer miles traveled per vehicle. In the wake of the Great Recession, industrial activity is recovering only fitfully, keeping diesel and gasoil demand growth tepid. In the US, new CAFE standards for 2017-2021 take another ~100-k b/d off 2020 gasoline demand over and above the prior estimate in last March's Energy 2020 report, a relatively small change within this timeframe, because fuel economy improvements take time to percolate through the entire vehicle fleet, but combining with other factors all the same. Oil to natural gas substitution is manifesting in a variety of ways, not least beginning to shave-off demand further from the heavy duty truck fleet, which is some 2-m b/d of diesel demand under fire. For more discussion on natural gas vehicles and the theme of oil-to-gas substitution, see Natural Gas: Bumpy Road to Global Markets (Anthony Yuen et al, 11 December 2012).

But fast-growing emerging markets, often represented for oil demand as the “non-OECD” country category in official energy agency data, are a different story. Asia, the Middle East and Latin America are driving rapid growth that is offsetting declines in the OECD. In recent years and going forward, global oil demand growth is being set by non-OECD countries’ demand gains more than offsetting OECD weakness. China has been at the vanguard of oil demand growth, growing more than 850-k b/d y/y in 2010 according to the IEA, but is likely to be structurally less of a bullish factor going forward, with both the pace and composition of economic growth easing, with 2012 seeing only 350-k b/d of growth (as per IEA's assessment). The double digit economic growth of the 2000s is over, while the weight of economic activity should shift (back) to the consumption sector. 2012 saw Chinese gasoline consumption grow strongly but diesel demand remain about flat year-on-year, exemplifying this shift. But the broader non-OECD story remains that of fast growth, particularly driven by middle distillates. The Middle East, in particular, sees young, fast-growing populations combined with subsidized fuel driving rampant growth.

Figure 47. Refinery capacity additions (closures) by region (2009-2017E)



Source: Citi Research

Refinery capacity is being built out quickly globally, generally close to those markets growing the fastest. Thus, Asia and the Middle East are seeing the fastest pace of growth in refining capacity, with China alone seeing around 500-k b/d in 2013, and 1-m b/d in both 2014 and 2015. Meanwhile, the US and Europe have seen closures in the last two years, as tepid demand growth combined with high (light, sweet) crude prices pummeled refining margins for less sophisticated refineries. In Europe, this led to some 600-k b/d of closures last year. On the East Coast of the US, the Philadelphia, Marcus Hook, Trainer and other refineries were slated to close, only for many of these to be bought or resuscitated. Nevertheless, North America still saw some 585-k b/d of closures in 2012 and 500-k b/d in 2011. More closures are expected in Europe in 2013. But now the US East Coast refineries may yet have a fighting chance as rail and barge brings light sweet crude from shale plays in the US midcontinent in force. As outlined earlier, there could be almost 900-k b/d of rail receiving/unloading capacity in the Philadelphia-area and other East Coast refineries, as well as intermodal rail-to-barge terminals at Albany, NY, and forthcoming, at Yorktown, Virginia, which bring further volumes to destinations on the East Coast. These crudes, at Bakken prices plus ~$15-16 for rail transportation, are competitive with Brent-related crude prices, which are as much as ~$25 higher than Bakken (priced at Clearbrook, MN). With the East Coast (or PADD I region) importing some ~500-k b/d of light, sweet crudes, mainly from West Africa, this is a sizeable market that can be cannibalized by Bakken crude, especially as it becomes freed up from Gulf Coast destinations with the rollout of pipelines south of Cushing, OK. As discussed in this report, the rapid unraveling of connectivity by pipes, rail and other transportation is pushing out imports not only on the Gulf Coast, but increasingly on the East and West Coasts of the US, and also the east coast of Canada.

Meanwhile, those refineries in the US midcontinent and on the Gulf Coast have been enjoying significantly cheaper crude feedstocks than their international counterparts, as WTI and related crudes in the US midcontinent and Western Canada have traded at severe discounts to waterborne crudes like Louisiana Light Sweet (LLS) and Brent. These wide differentials have been necessary to incentivize the mopping-up of the crude glut any way possible, whether by rip-roaring rates of utilization at these refineries (EIA has reported PADD II and PADD III region refineries at higher-than-historical rates over the last year or two), or by moving crude out of congested areas by new pipelines, rail, truck, barge or donkey, if necessary.

High rates of utilization and corresponding throughput has boosted production of gasoline, diesel and other petroleum products, even as US product demand has been rather weak. This growing surplus of products is showing up in the rapid fall of net imports of petroleum – total crude and product net imports have fallen from over 12-m b/d in 2007 to under 7-m b/d by the end of 2012 – and indeed, growing net exports. The US is now a net exporter of well over 1-m b/d of products, most recently switching from a net importer to a net exporter of total gasoline (including blending components). The closest natural import market for US exports has been Latin America, but Europe too, where refinery closures have lessened its gasoline surplus and exacerbated its distillates deficit. Venezuela in particular has seen a myriad of problems at its Amuay, Cardon and other refineries lead to severely challenged local product supply, and the sourcing of products from the US to cover the shortfall. As the home of several fast-growing emerging markets, Latin America should continue to exert a strong pull on US product exports. The massive build-out of infrastructure debottlenecking the US midcontinent crude glut should bring in the WTI-Brent differential in 2013, lessening this benefit over time. But the "first cause" remains that North America is getting longer crude and US refiners retain a long-term advantage even with short-term volatile fluctuations of landlocked US prices versus global prices. See "US Independent Refiners" (Faisel Khan, 22 January 2013) for further details on the outlook on the sector."

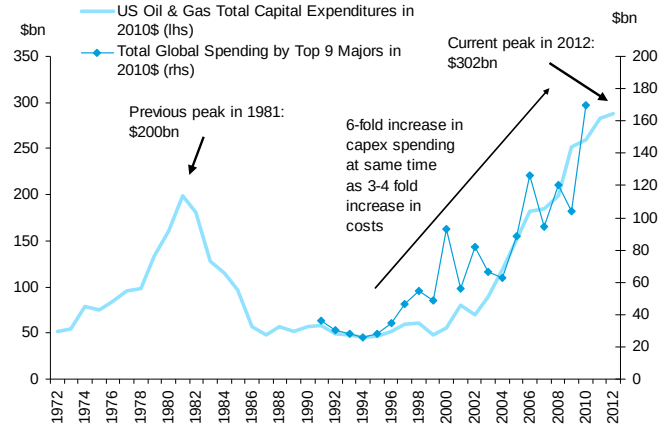
But not only has the shale revolution benefited US refiners by providing them access to heavily discounted light sweet crude oil (at least those in the midcontinent and the Gulf Coast), but the “original” shale revolution in natural gas has provided cheaper fuel for power generation as well as feedstock for other processes, including production of hydrogen for refinery processes such as hydrocracking or hydrotreating. This double whammy is proving to be twice as nice for US refineries, as cheap, abundant gas and oil give them a “permanent” structural advantage globally. [1]

Long-term oil prices

Citi's Commodities Strategy team has written on long-term oil prices; Brent looks likely to stabilize below $90, perhaps falling well below these levels at times and as a result the current $90 floor price for Brent looks likely to become a ceiling price by the end of this decade. The period of price increases that started in the last decade appears to be coming to an end. High prices have stimulated a six-fold increase in global upstream capital expenditures, driving a new round of global supply that is bringing on deepwater, oil sands and shale oil resources into production. There are four broad approaches to zero-in on long-term oil prices.

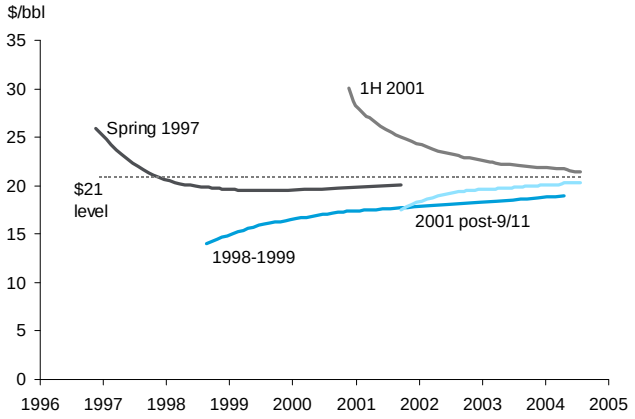
[1] For a more detailed look at the US refining sector in relation to the North American supply revolution, see “US Independent Refiners: Remain Neutral; Pipelines, new Capacity and Basis Remain Risks by Faisel Khan, 22 January 2013 on Citi Velocity.

Figure 48. Total US and global oil and gas capital expenditures from 1972 to present



Source: Oil & Gas Journal, Citi Research

Figure 49. Long-term 60-month deferred WTI prices saw mean reversion around $21/bbl, mid-1980s through 2002

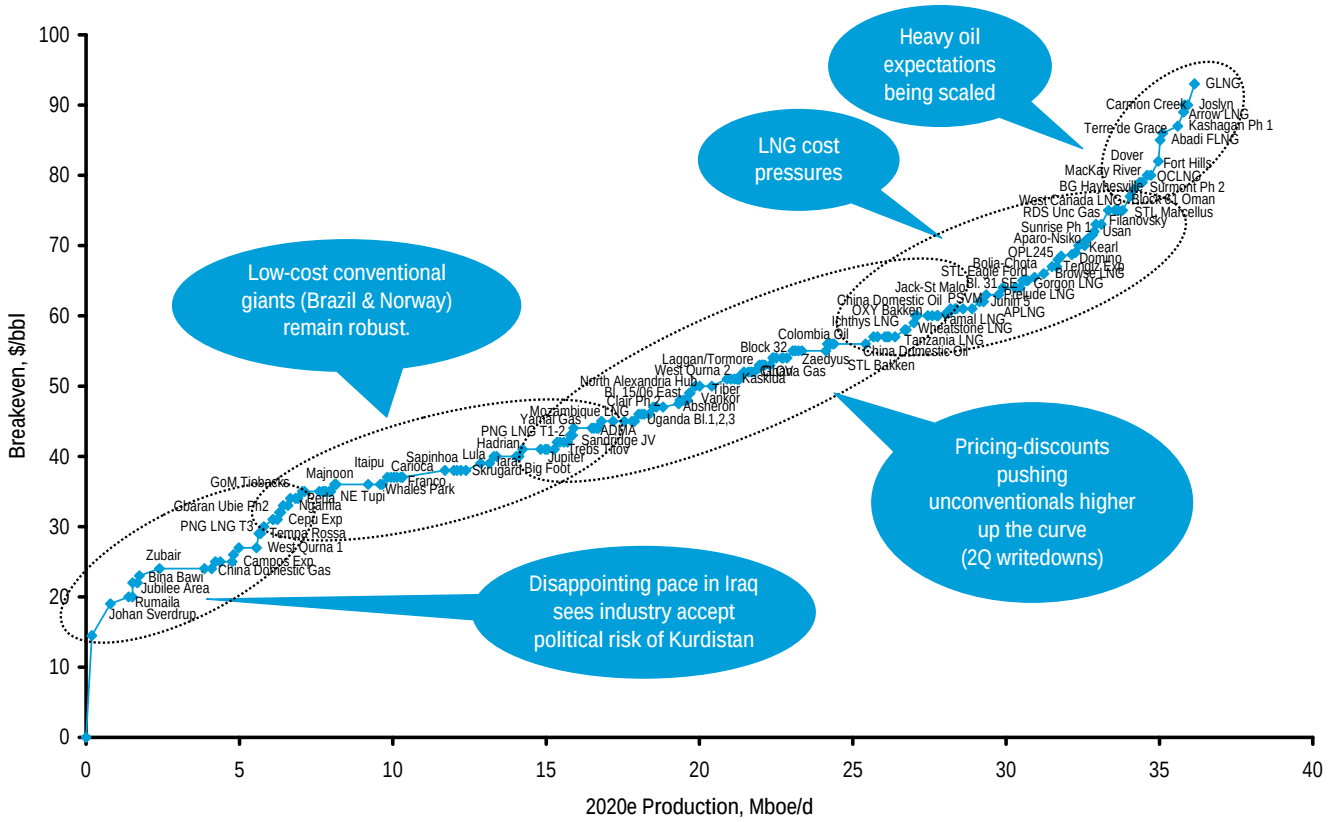


Source: Bloomberg, Citi Research

Firstly, long-term deferred prices in the futures market, which used to mean-revert around $21/bbl through the mid-1980s to 2002, after which deferred prices rose to over $140/bbl in the summer of 2008 before stabilizing at $90. These prices are required to bring on the new supply in the world,

A second approach reviews marginal project breakeven prices; these recently were at the $50-70 level for deepwater, $50-80 level for shale, and $90 level for oil sands (see Figure 50). In our view, there is further upside in the $50-80 portion of the curve.

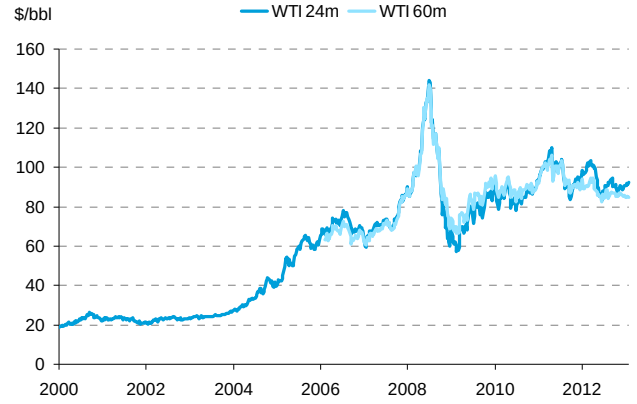
Figure 50. Marginal project breakeven prices for 2020 developments



Source: Citi Research

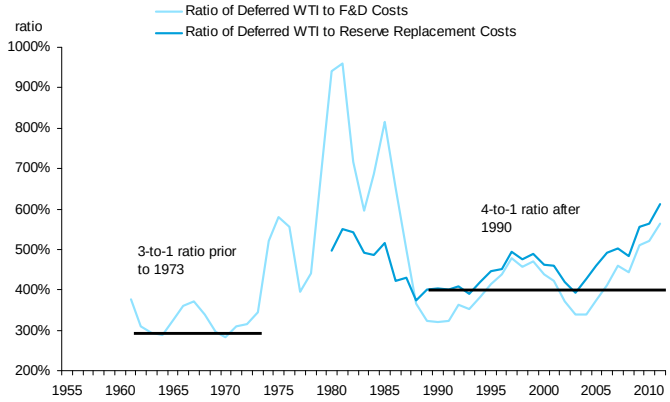
An examination of long-term prices and their relationship to unit costs of production of oil is a third approach, and also suggests target prices at a lower end of $65-70/bbl, or roughly four times global finding and development costs of $17-18/bbl. This relationship should take into account project economics, reservoir depletion rates and discount rates.

Figure 51. 60-month deferred prices, WTI and Brent, 2002-2012 (24-month WTI before 2006) – prices have settled at a new stable $90 level



Source: Bloomberg, Citi Research

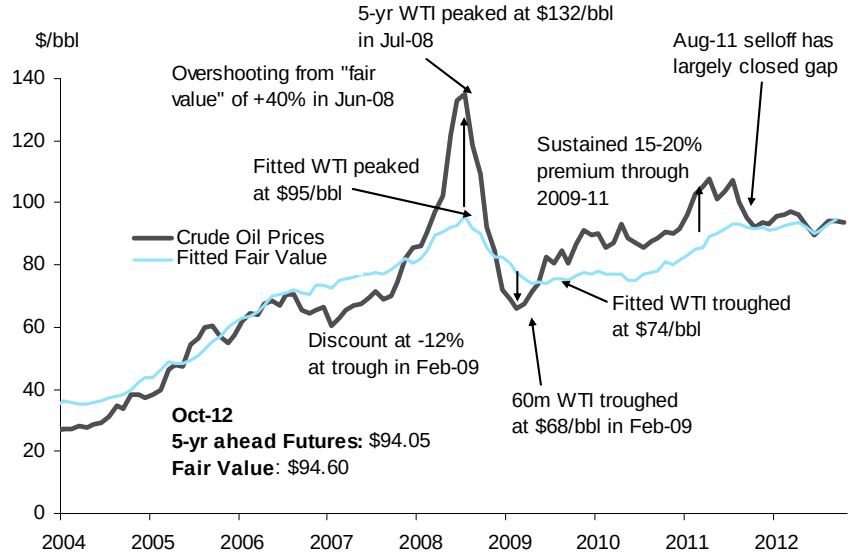
Figure 52. Ratio of deferred WTI price to unit costs of production, points to $65-70/bbl oil



Source: IHS Herold, Citi Research

Finally, Citi's proprietary "fair value" index looks at industry cost indices and their relationship to long-dated WTI futures, based on cost data from the US Bureau of Labor Statistics. The "fair value" index is close to the level of WTI today (around $85-90/bbl), providing further weight to the conviction that long-term oil prices should converge at this level, or below. For more detail, see Zeroing In On Long-Term Oil Prices (Edward L. Morse et al, 4 June 2012).

Figure 53. Citi's proprietary cost index points to $85-95/bbl "fair value" for deferred WTI prices



Source: US BLS, Citi Research

It is of course impossible to forecast future disruptions to supply or future levels of cost inflation in the oil and gas sectors. But to the degree that there are tested ways of estimating where prices are heading, it looks reasonable to assume that prices will stabilize in a much lower range than today's, given supply increases as frontier oil develops both in the deepwater and shale plays globally. Bringing average prices down from today's range to a level where $90 is an effective ceiling price has grave consequences for the geopolitics of oil.

Part II: The result is a very big difference for foreign policy and geopolitics

There has been a superficial assumption that the profound changes in the North American energy landscape should not have much of an impact on either US energy security or on the geopolitics of energy. That assumption stems from an obvious but misleading conclusion: that global oil markets are susceptible to supply disruptions and price spikes and there is no way to immunize the US economy from traumatic global events, mandating that the US continue to seek and protect diverse sources of supply.

That many reach this conclusion is not surprising; neither is it accurate. It's not surprising because it is hard to accept the view that dramatic changes are unfolding, including changes that affect time-tested assumptions about the global economic and political environment. When it comes to foreign policy, old truths linger long after they have lived a useful life. Just as analysts of the Cold War could not readily accept the demise of the Soviet Union in the early 1990s, so too do analysts who focus on emerging changes find it difficult to change their biases when it comes to petroleum. In both commodity analysis and foreign policy analysis the general thesis is of continuities; yet in reality, the commodity sector – and above all the petroleum sector – is characterized by a series of discontinuities, challenges and adaptations, and this has critical implications for oil and geopolitics.

Let's take a look at four simple and clear issues in the accepted, conventional wisdom:

- US oil consumption will rise indefinitely, and the increase will taper off or decline only for short-term and transitory reasons;
- US oil and gas production will decline annually, resulting in ever-increasing imports;
- The price of oil and natural gas will rise annually, all else being equal;
- The cost of finding and developing oil and gas will continue to rise because it is harder to find hydrocarbons, because decline rates are rising, and because the physical costs of oil industry goods and services embody built-in inflationary conditions.

None of these old truths can now be taken as a given. Changing driving habits (partly the result of higher prices over the past decade, partly a result of demographic shifts), impactful public policy aimed at increasing fuel efficiency and encouraging biofuel supplies, the application of new technologies not only in transportation (hybrid vehicles, natural gas vehicles) but across the oil chain, including finding and developing new hydrocarbon resources, and the rapid scalable growth in supply of drilling equipment have coalesced to changed these assumptions. Now, and for a long while to come, it appears that the new realities are:

- US oil consumption will fall, either ratably or quite probably on an accelerated path, over the next decade or two;
- US and Canadian oil and gas production (and as we have seen in the last section, Canadian production will remain "trapped" in the US market for years to come) will increase annually for as far into the future as can be seen, perhaps for as long as 20 years;

- The price of natural gas has declined radically and it looks likely to stabilize in a much lower range than had previously been forecast – Citi projects a range of $4 to $5.50/MMBtu – and there are emerging signs that the price of crude oil will decline over time as well, with pressure on the price of Brent persisting for years to come;

- The costs of finding and developing natural gas in unconventional plays have declined; and, once temporary inflationary conditions are overcome, the costs of finding and developing oil in deepwater and in tight formations and in oil sands are both different from historical conventional costs and are on a path toward declines. (Conventional oil and gas have steep upfront costs that require paybacks over a period of years; unconventional hydrocarbons, particularly shale gas and tight oil, have very short payback periods and generate returns on an almost "just-in-time basis.")

The increase in North American hydrocarbon supplies has been stunning and actually accelerated after 2007, and similar comments can be made about the decline in consumption of petroleum products, particularly in the United States. The rise of abundant shale gas also has direct repercussions for oil demand, as inroads are likely to accelerate – and not only in the United States – in the use of LNG as a transport fleet for rail, trucks and shipping. Our reports have focused on what's happening in the US, but in Europe heavy tax burdens on petroleum products make natural gas highly competitive with oil. And at the end of the day, the shale gas and shale oil supply revolutions should spread to the rest of the world, albeit in fits and starts. But a technological revolution of the sort now unfolding in the US is unlikely to be limited to such a small part of the planet.

The supply revolution is tangible. But what in the end does it really mean? It's time to clarify what energy independence is – and is not – and what the geopolitical consequences might be.

What does self-sufficiency mean? What does it not mean?

There are numerous skeptics of the thesis that the US becomes net self-sufficient in oil. They have been wrong for several years and it is our view that they should continue to be proven wrong. That's an empirical question. But they are also skeptical about whether there are any consequences, let along significant ones, of energy supply self-sufficiency. We assume we are correct about the volumes of crude oil and other liquids production and consumption to set the parameters for a debate over whether there are important consequences to consider.

Does energy self-sufficiency insulate the US from global price spikes from disruptions and price volatility? No – and yes.

Skeptics have rushed to judgment on this issue. Clearly if the US remains an integral part of the global economy, price changes induced by tighter global balances will impact the US market. But there are two implications of Citi Research reports on this matter:

First, Citi notes that the US supply resurgence is part of a global rebirth of upstream exploration and production investments, which will usher in a period of lower prices, a period that the International Energy Agency echoes in its most recent *Medium-Term Oil Market Report 2012* and in its latest *World Energy Outlook 2012*. The IEA sees the average import price of IEA member countries falling from $110/bbl in 2011 to $89 by 2017, a level fully consistent with Citi's long-term oil price outlook, as discussed earlier and in the report, *"Zeroing in on Long-Term Oil Prices"* (Edward L. Morse et al, 4 June 2012). High capital expenditures are resulting in larger new

reserve discoveries at a time when the runaway demand growth outlook of the last decade in emerging markets appears to have hit a turning point. Indeed in some cases it might have reached a tipping point, as non-transportation fuel demand is phased out and as engine efficiencies improve. A lower price path is consistent with 150 years of boom and bust cycles in the oil sector (indeed, in all commodities), and lower prices portend a significant reduction in the currently high or near record share of energy in global GDP. That means significantly lower price impacts from future disruptions.

Our projections, plus other evidence, make it highly probable that today's price *floor* of $90 for Brent will likely be the price *ceiling* for Brent's traded range by 2020.

Does a petroleum surplus afford enhanced energy security and greater protection? Decidedly, yes.

That's because an energy surplus for North America means effective spare capacity, whether in petroleum or petroleum products or natural gas. The US has already reached this position in petroleum products, which also depicts clearly a country whose energy economy is disjointed. The center of the US – the Midcontinent-Gulf Coast area – is now an exporter of petroleum products, while the east and west coastal areas of the Lower 48 states are petroleum product-importing sectors. Soon the US should become surplus in natural gas as well, with a diminishing trickle of imports from Canada and seasonal imports of LNG.

This means, in case of an international emergency or a supply disruption, exports can be curtailed and domestic prices could in theory be significantly cushioned from international shocks. Indeed, the government could restrict or even ban exports in times of emergency, pulling the exported surplus back into the country and causing a price discrepancy between reduced priced domestic supply and international supply. To be sure, that is an extreme that could possibly violate certain international trade treaty obligations, especially if the potential export ban impacted free trade partners. But the point is that an export surplus is another form of surplus capacity and provides benefits to the economy and to the country's citizens. Among those benefits is partial insulation from price shocks. Couple this with a robust strategic reserve, and energy independence has tangible meaning for US security, a protection that China does not come close to having.

In a similar vein, lower prices and excess production channeled into export markets should also reduce the economy's exposure to global price volatility. Disruptions along the supply chain should see a decrease in the scale and frequency of reverberations, for the same reasons associated with the buffering that strategic stocks, commercial inventories and spare production capacity can also work to mute price changes in a properly functioning market.

Does energy self-sufficiency afford the country an opportunity to be isolationist? Almost certainly not.

While US energy independence will do much to strengthen the US position on a variety of levels, we do not think that it suggests a return to the fleeting period of US sole superpower status; this change, however profound, does not mean an end to a multi-polar world order in and of itself. It does mean that the US can deploy its still-unsurpassed military power and economic might in pursuit of a host of other trade and foreign policy objectives that suit its national interests.

In an age of globalized trade and commerce, international terrorism, of cyber- and biological warfare and of all of the other factors associated with economic and security interdependencies and globalization, the national security borders of the

US are effectively totally global. The security and openness of sea-lanes remains a core international concern. The security of supplies from the Middle East and elsewhere remain important to the US because it is important to the world and because it is not in the US interest to allow China or any other potential rival control over these resources. Indeed, the continued military presence of the US in the Middle East could be important to the maintenance of oil price moderation globally because of the security to producer allies thereby implied.

The extension of the US security guarantee is equally likely to be sought by Gulf producers in the aftermath of the Arab Spring and continued regional volatility. With this in mind, as much as the US has been accelerating the so-called Asia pivot in foreign and security policy post-Iraq withdrawal, longstanding relationships and continued mutual interests are likely to mean that these links endure on some level, if perhaps less pronounced than in decades past.

Does energy self-sufficiency matter? Yes, indeed.

There are three areas where sustained energy self-sufficiency makes a big difference:

1. The current account deficit of the United States has been a major element of global imbalances and a major challenge to the role of the US dollar in international commerce. The current account deficit is about 3.2% of GDP and the oil import bill alone is 1.7% of GDP. Our own modeling has indicated that energy self-sufficiency combined with the consequences of low natural gas prices on the re-industrialization of the US economy could reduce the current account deficit by up to 2.4% of GDP with an associated improvement of the US dollar between 1.6% and 5.4%. The improvement in the current account deficit comes not just from the direct reduction in hydrocarbon imports and emergence of exports but also the fall in overall oil prices and the value-added exports in related manufactured products such as petrochemicals and metals that should accompany the hydrocarbon supply boom. To be sure, questions remain about the degree to which gains in national income would be saved rather than consumed and the initial improvement in the current account may be muted by the need for fixed investment to develop infrastructure. However, in the longer-term, the effect on the current account can be only positive. Directionally this makes a big difference in reducing tangibly and potentially completely one of the main vulnerabilities to US superpower status for most of the rest of the next generation and perhaps beyond. (A similar argument can be made about the fiscal imbalance but that can be debated elsewhere.)

2. Oil import dependence has been a second challenge to US global dominance. The elimination of that dependence beyond Canada places the US in a unique position among potential global rivals. Neither China nor the European Union can entertain this possibility. And as far as Russia is concerned, maintaining current levels of oil prices, as well as the linkage between natural gas and oil prices, appear to be major challenges to its continued ability to foster its national interests via the oil and natural gas sectors.

3. Values-based foreign policy. Finally, to the degree that the US has been forced to compromise the pursuit of certain foreign policy goals because of the importance of bilateral ties to key oil exporting countries, undoubtedly self-sufficiency in oil and gas could make a significant difference (recognizing the perils and pitfalls of a foreign policy that emphasizes democratic and human rights values at the exclusion of other objectives). After an extended period of interest-based foreign policy, and given the slow trajectory of policymaking, taking advantage of this opportunity may be slow to transpire.

Challenges for OPEC

North American energy independence has profound consequences for the geopolitics of energy, at the center of which is OPEC

As we have argued through the heart of this report, there are tangible, significant, and potentially transformational consequences of North American energy independence on the institutional structures governing global oil and gas, including on the oil side the IEA, the International Energy Forum and especially OPEC. In short, North American energy independence has profound consequences for the geopolitics of energy. These consequences first and foremost impact who counts when it comes to price determination. Energy independence dramatically affects the drivers of price at a time when oil producing countries are seeing their fiscal requirements increasing and hence as in no other time historically have a stake in indefinite increases in oil prices. Related to that is the issue of burden sharing when it comes to price changes and adjustments to those changes. OPEC as an institution was designed to protect its members from the burdens of adjustment to lower oil prices and to push the burden of adjustment onto oil importing countries. With its lost market share in the US and potentially elsewhere, some oil producing countries could find the burdens of adjustment very difficult to confront politically. Tangibly, as we have seen, the loss of market share in the US for key OPEC producers cannot be easily made up elsewhere quickly, given the global refinery configuration. But this is coming at a time of conjunction with other factors that are already pressuring OPEC unity.

OPEC's global export market share is being whittled away by rampant internal demand

The restricted investment and output of OPEC in the 1990s and early 2000s – at the same time as the rocketing of demand of China and the BRIC countries – saw nominal oil prices rise from lows of $10/bbl levels in 1998 to almost $150/bbl in summer 2008. OPEC revenues have ballooned from $251 billion in 2000 to $771 billion in 2010 and a record $1.05 trillion in 2012 (all nominal US dollars).

Such a revenue bonanza has fed economic expansion and been channeled into subsidized energy prices that are well below global market levels – for instance, domestic gasoline prices are as low as 9-10 cents per liter in some OPEC countries, including Venezuela. This has led to surging internal demand in OPEC oil producer countries, where OPEC refined product demand has grown from 5.4-m b/d in 2002 to 8.3-m b/d in 2011; in Saudi Arabia alone, electricity generation by burning crude oil directly can rise to 800- to 900-k b/d levels at the summer peak, causing further seasonal spikes. Alongside stagnating production capacity, this eats into OPEC's exportable hydrocarbons surplus, reducing global market share over time, and slowly eroding the cartel's market power.

The Arab Spring has also put the spotlight on governance issues in OPEC and is driving rising social spending that would require increasingly high oil prices to finance

Meanwhile, the wake of the Arab Spring has left oil producing countries on the defensive, attempting to assuage domestic populations by raising social and economic expenditures further. Tighter fiscal balances could make it hard to publicly agree to collective OPEC production cuts. Higher expenditures require corresponding revenues; the implied breakeven price of oil that these oil producer countries require to raise these revenues to balance bloating budgets is what is meant by the so-called "fiscal breakeven" price of oil. Fiscal breakeven oil prices are on the rise, with many now above $110/bbl. Meanwhile, OPEC negotiations may, over time, come under closer scrutiny by a more politically engaged public as a result of the evolving social currents in the Middle East and North Africa.

Figure 54. Fiscal breakeven oil prices for selected oil producer countries ($/bbl)

Country	Fiscal breakeven oil price
Algeria	$105
Bahrain	$119
Iran	$117
Iraq	$112
Kuwait	$44
Libya	$117
Oman	$77
Qatar	$42
Saudi Arabia	$71
United Arab Emirates	$84
Yemen	$237
Russia*	$110

Source: IMF, *Citi Research

The North American supply revolution challenges OPEC's influence in oil price determination, eliminating itself as a destination market and emerging as a competitor

The global market has been adjusting to high oil prices, which has stimulated capital expenditures in upstream exploration and production to soar six-fold from the 1990s through 2012. At the same time, investment in alternative sources of energy has been rising, as has re-regulation of the energy market with government after government targeting or incentivizing energy efficiency. On top of this, a new and emerging abundance of natural gas is creating opportunities to substitute it for more expensive crude oil-derived products, particularly through the direct use of gas in transportation, as well as production of liquid fuels from natural gas. These factors – along with demographic changes in mature economies – have already been driving a secular decline in oil demand in the OECD countries, and the prospect of natural gas vehicles and switching of heating oil to natural gas for residential/commercial space heating can take a further bite out of oil demand.

But the most dramatic changes are happening on the supply side, with this report – and the previous Energy 2020 report, "North America, the New Middle East?" — discussing the impacts of rising production and falling import requirements.

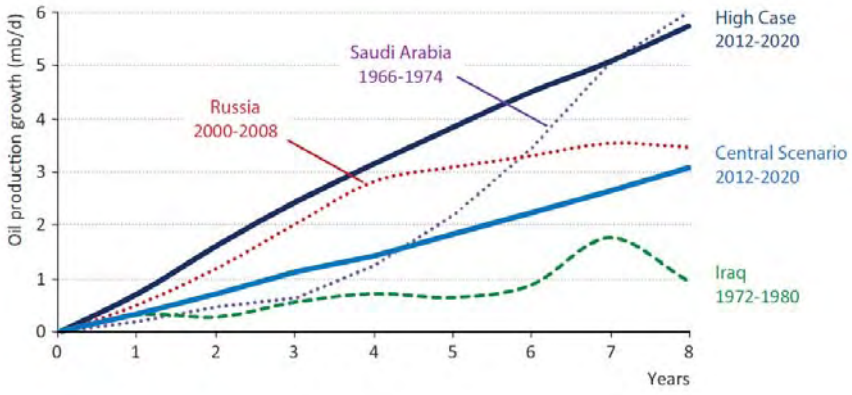
As discussed in this report, shale oil, deepwater and oil sands have been, and should continue to be, major drivers of production growth in North America, and globally (and the growth of biofuels has also added volumes). Deepwater resources require prices of $50-60 (2010 $s) to encourage long-term exploration and development, while oil sands have cost curves in a wider range, with some projects under $50 and others closer to the $90 level for project breakevens. Shale oil requires some $50-80 to allow commercial development. These price needs are significantly higher than those prevailing before 2002, which were mean-reverting around $21. But they could also ease over time with competition in the services sector and technological innovation.

This is a dilemma and an irony for OPEC. OPEC fiscal breakeven requirements for oil prices are rising, encouraging cartel production policies to keep prices high, but this also subsidizes production in the sources of unconventional oil mentioned above. A combination of competitive, unconventional sources of oil, as well as potential supply growth within – from Iraq or Venezuela post-Chavez – look likely to challenge the coherence of OPEC policy.

The reemergence of Iraq tests OPEC coherence

Iraq's oil potential is massive, with the IEA's recent report seeing future production rising from 3-m b/d levels today to 4.2-m b/d by 2015 and 6.1-m b/d by 2020 (see the IEA's *Iraq Energy Outlook*, 9 October 2012) though there remain risks to internal security and tensions between Baghdad and the Kurdish Regional Government. As its production rises, there should be growing calls for Iraq's reintroduction to the quota system. But Iraq's historical oil output has been struck down time after time by wars, sanctions and reconstruction; Iraq hit peak output levels just before the 1980 Iran-Iraq war, but is only now looking to push past this level. During this time, other OPEC countries have increased market share; Iraq's inability to do so has been a sore point for its people, and politicians should be sensitive to this. As a rare example of a democracy in the region, Iraq's citizens may have more bearing on decision-making with regards to OPEC, and may reject any production quota until production breaks over 6-m b/d. This could present a further challenge to OPEC unity and production policy.

Figure 55. Iraq production outlook to 2020



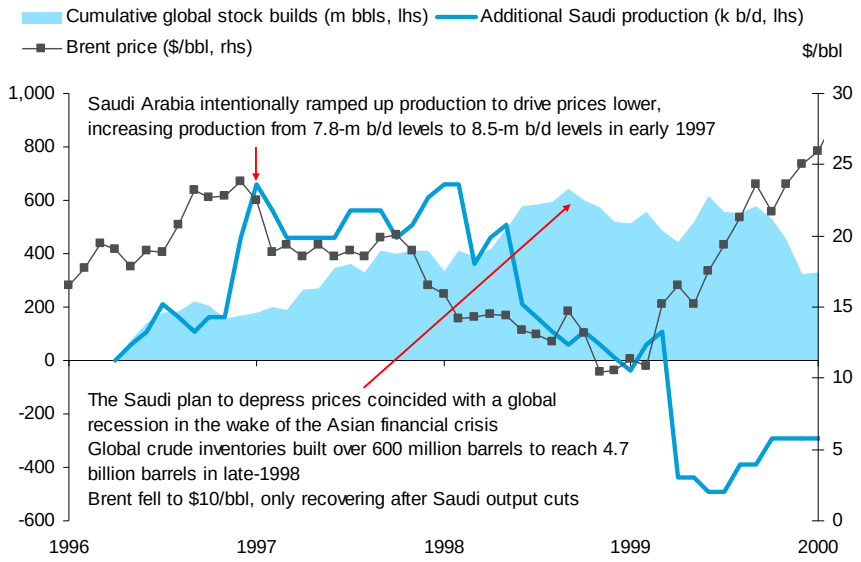
Source: IEA Iraq Energy Outlook, 9 October 2012

Can Saudi Arabia remain a credible swing producer to the world?

Saudi Arabia is the only country with substantial spare productive capacity that is left idle; it then reserves the ability to raise production to bring down prices, and potentially punish those fellow OPEC producers that stray from output quota commitments. Saudi Arabia looks to have 1- to 2-m b/d of spare capacity as of the winter of 2012-13 – lower than past levels. From 2005-10, the Kingdom invested $14 billion to increase productive capacity from 10- to 12.5-m b/d; more recently, Saudi Arabia has been developing the giant Manifa field which could add 900-k b/d of production capacity, but this would merely maintain its 12.5-m b/d total capacity, offsetting declines elsewhere.

With regional and internal challenges, the Kingdom faces competing priorities: on one hand, spending on social services and defense, and on the other, major investment in its oil sector as well as alternative energy sources such as shale gas and solar energy. Over time, it should become increasingly challenging for Saudi Arabia to "overproduce" and bring down prices to punish wayward OPEC members; without this disciplinary mechanism, it is unclear whether OPEC can remain cohesive.

Figure 56. Saudi "overproduction" during an economic recession in 1997-99 led to stock builds, depressed prices



Source: EIG, Bloomberg, Citi Research

Saudi Arabia's domestic challenges are a case in point for other regional oil producers. It is politically difficult but economically expedient for the Kingdom to normalize its internal energy prices, slow down its rate of demand growth, diversify its power generation away from oil and thus free-up more hydrocarbons for the lucrative export market.

Subsidized hydrocarbon costs internally in Saudi Arabia mean it enjoys low fuel prices and petrochemicals feedstock prices, but this is a double-edged sword, as it also means overconsumption and insufficient supply of the same. Petrochemicals have been advantaged in the Middle East due to traditionally low energy and feedstock prices, but is this sustainable? Meanwhile, the US is becoming extremely competitive.

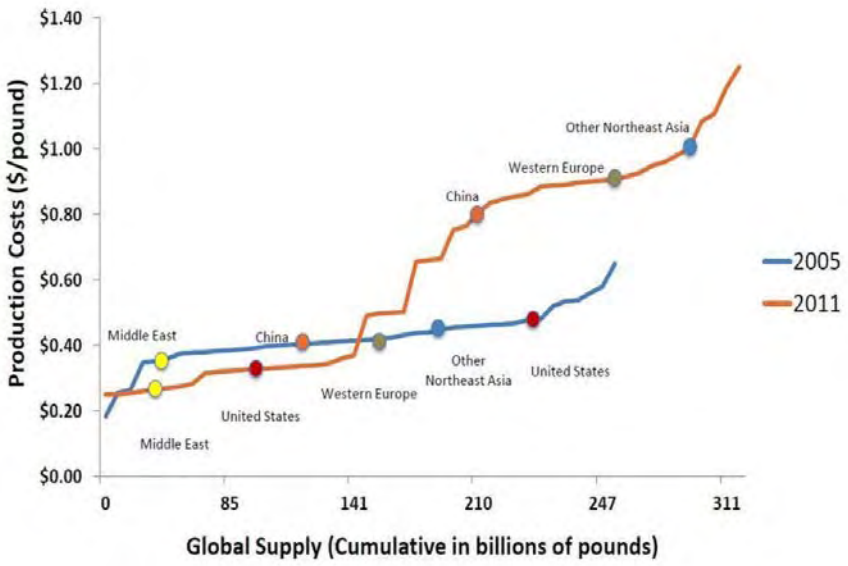
Petrochemicals have been advantaged in the Middle Eastern region due to traditionally low energy and feedstock prices, but is this sustainable? At the same time the US is becoming extremely competitive

Saudi Arabia's energy consumption per capita exceeds those of most industrial nations. It consumes a quarter of its oil production, cutting into its (lucrative) exportable surplus. In particular, crude oil is directly burned for power generation, and during summer peak usage (for seasonal air conditioning demand), the burn rate has been as high as 900-k b/d. Peak power demand is growing by almost 8% every year; a simple projection of this power demand growth without any change in the power generation energy mix points to an elimination of Saudi Arabia's oil surplus by 2030. Saudi natural gas (mostly produced as "associated gas" alongside oil production) is already all consumed at home. Similar issues face the other Gulf Cooperation Countries (GCC). The Kingdom has announced plans for nuclear and renewables to target 50% of power generation by 2030, but nuclear in particular faces risks due to lack of expertise, plant safety risks in keeping plants cool in a hot, desert environment with scarce water resources, and the potential for cost overruns. Thus, though petrochemical feedstock costs are among the lowest in the world, availability is becoming tighter and costs could rise and utilization rates could fall. And for illustrative purposes, a 10% reduction in Saudi Arabia's petrochemicals operating rates would translate to a 7% downward impact on globally traded polyethylene volumes. Given the growing abundance of shale gas in the US and

thus cheap energy and feedstock costs, a North American energy-intensive industrial renaissance is beginning. The US may also benefit from proximity to North America and other relevant markets.[2]

A deflationary trajectory for medium-term oil and gas prices do not help the situation. Raising domestic prices to curb overconsumption faces the risk of unsettling dissatisfied domestic populations.

Figure 57. Global ethylene cost curves in 2005 and 2011



Source: CMAI, ACC, Citi Research

These factors figure broadly into the downsides of investing in petrostates. Both the downsides and upsides are discussed by Citi economists and strategists in Global Theme Strategy: Investing in Petrostates (Kingsmill Bond et al, September 4, 2012).

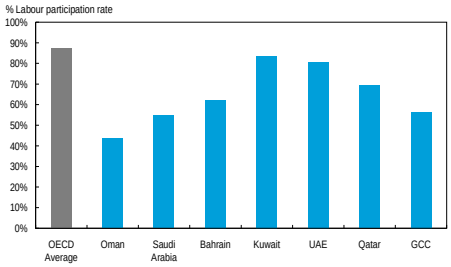
In an illustrative scenario of $60 oil prices, Middle Eastern oil producers would be hard hit

Citi Middle East economist Farouk Soussa[3] has examined an illustrative scenario of $60 Brent to highlight the challenges faced by Middle Eastern oil producers, as well as teasing apart some of the regional differences among them. As discussed in "Zeroing-In On Long-Term Oil Prices" (Edward L. Morse et al, June 4, 2012) and summarized in this report on in the previous section titled *Long-Term oil prices*, Citi's long-term oil price outlook is for prices in the $65-90 range – a wide range, but hinging on $90/bbl Brent as a ceiling price for oil (though of course, short-term disruption could lead to spikes above).

Such a price drop is a revenue shock for Middle Eastern oil producers, who depend heavily on oil revenues. Meanwhile, their spending patterns have risen, with the 2011 social expenditure hikes ranging from over 20% in Saudi Arabia to 30% in Kuwait, and an even larger 38% in Oman and 41% in Bahrain.

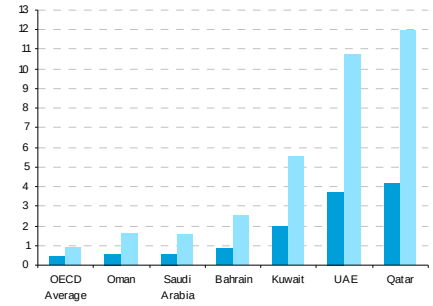
[2] See "Saudi Petrochemicals: The End of the Magic Porridge Pot?" and "Petrochemicals Primer: All About the Oil Price & GDP", both by Heidy Rehman, 4 September 2012.
[3] See "Middle East Macro Monthly", Farouk Soussa, 27 February 2012.

Figure 58. Job participation rates lower in Oman, Saudi Arabia, Bahrain



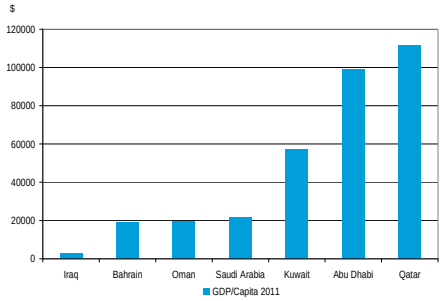
Source: National sources, Citi Research

Figure 59. As are jobs available per national of working age



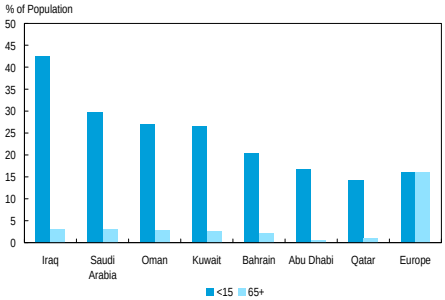
Source: National sources, Citi Research

Figure 60. Personal wealth is higher in Abu Dhabi, Kuwait, Qatar



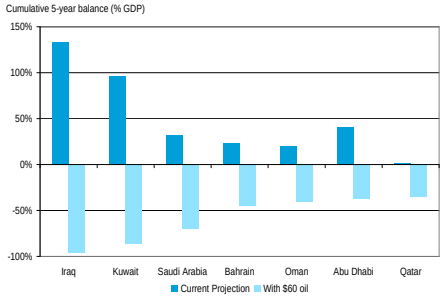
Source: Haver, Citi Research

Figure 61. The youth bulge is visible across the region



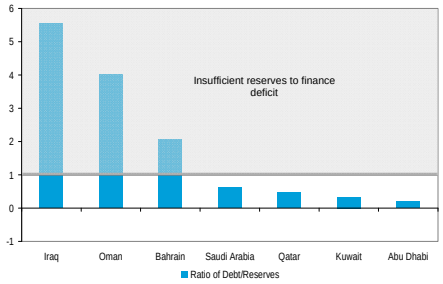
Source: Population Reference Bureau, Citi Research

Figure 62. Illustrative $60 oil price scenario hits fiscal balances severely



Source: Citi Research

Figure 63. Bahrain, Iraq, Oman would have insufficient fiscal reserves to weather $60/bbl



Source: Citi Research

Given maintenance of the political status quo in Middle Eastern oil producers, there is a policy trade-off between social spending to assuage restless populations, and unsustainable fiscal imbalances

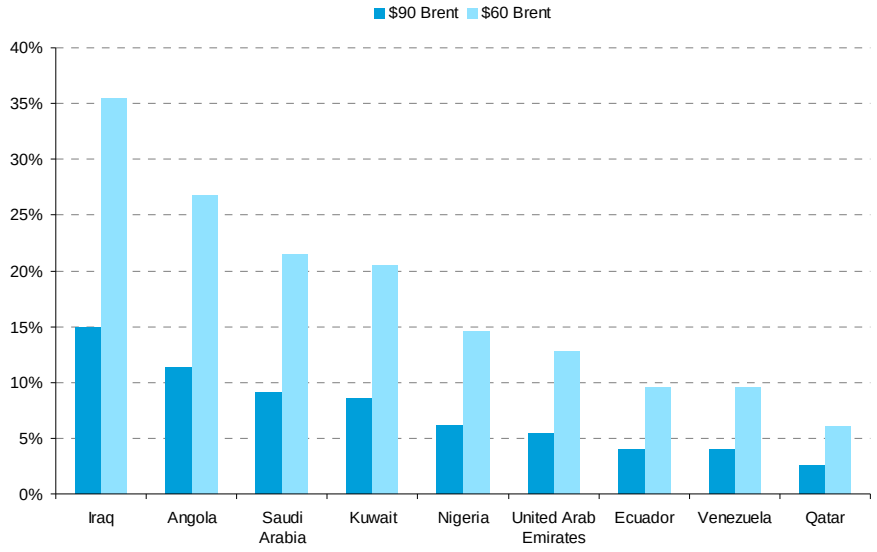
The policy dilemma thus faced is whether to give higher priority to economic growth (and by extension, social stability) or to avoiding potentially large fiscal imbalances from emerging. How the chips fall depends on firstly, the sociopolitical costs of reduced economic growth, and secondly, the affordability of de facto loose fiscal policy to avoid these same sociopolitical costs. These sociopolitical costs are particularly acute in Iraq, Bahrain, Oman and Saudi Arabia. In these countries, labor force participation is particularly low, with an exceedingly young population (over 50% of the local population under 21 year of age). Job creation to alleviate high unemployment – a major background factor behind the Arab Spring – is particularly urgent in these countries. Iraq faces particularly severe economic hardship given much lower per capita GDP and much reconstruction of infrastructure in housing, electricity, transportation, healthcare and education still needed on an ongoing basis. However, Saudi Arabia has significant resources to weather higher social spending, at least in the short- to medium-term.

Kuwait, Qatar and Abu Dhabi face lower sociopolitical costs; they enjoy a relatively small and wealthy local population. In any case, they have more comfortable cushions to assuage these should they arise. Without these cushions, Iraq, Bahrain and Oman would need to rein in expenditures or find other sources of financing continued social spending to avoid unrest.[4]

[4] See "Middle East Macro Monthly: Can The Gulf Stay the Course with US$60 Oil?", Farouk Soussa, 27 February 2012.

If diversification of the economy away from hydrocarbon revenues is not meaningfully attained, and social spending cannot be raised further due to unsustainable fiscal imbalances as oil prices fall and stay below the fiscal breakeven oil price required by these oil producers, the possibility of another round of Arab Spring unrest and/or a collapse into failed statehood is not inconceivable.

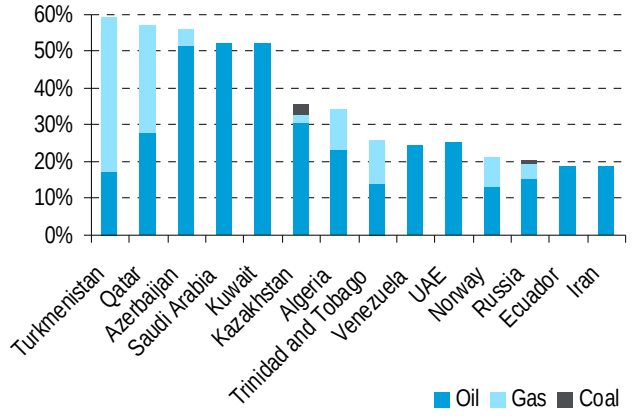
Figure 64. Estimated oil export revenue loss in % GDP of selected countries in a $90 Brent and $60 Brent scenario, versus 2012's $112 average Brent price



Source: IEA, IMF, Citi Research

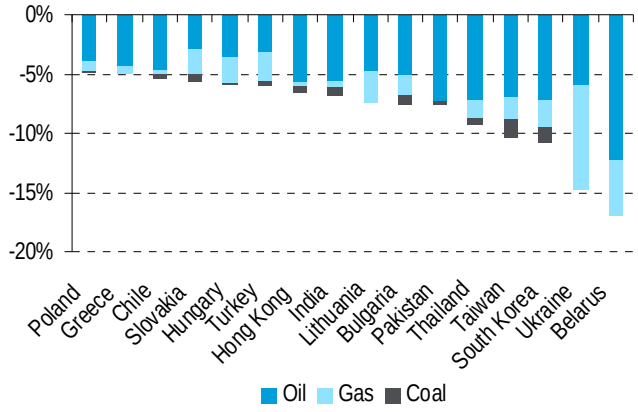
In short, Middle East OPEC members, have a history of remarkable adaptation to changing conditions. One should not underestimate the ability of these countries to meet the extraordinary challenges ahead of them, just as they have in the past. The dilemmas between higher social spending and dramatic changes in conditions at home are clear and also palpable. But OPEC has survived the past fifty years. The challenges of the future are formidable and unprecedented, but they might well be met as they have been in the past; OPEC may yet emerge a more unified oil exporting club, even though the odds look like they are against that happening.

Figure 65. Petrostates' net energy exports, % GDP, stand to lose from easing oil and gas prices...



Source: Citi Research

Figure 66. ...while energy importers stand to gain



Source: Citi Research

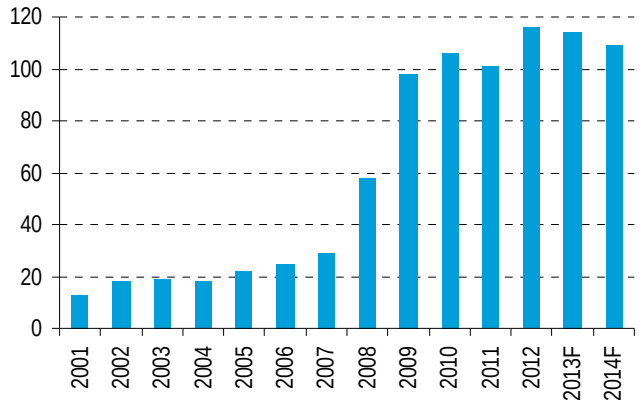
Challenges for Russia

North American energy independence helps undermine the price of global oil and gas, the main driver of the Russian investment case for the last decade, and should have significant impacts for the Russian economy and politics. The silver lining is that it may also over time help to release Russia from the curse of oil and turn it into a more normal market.

The dependency of Russia on oil

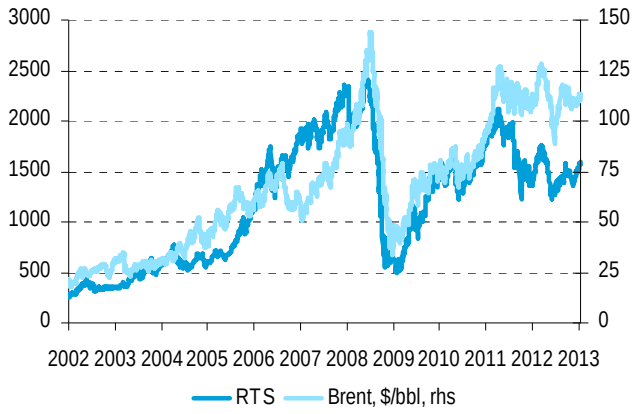
One consequence of North American energy independence is likely the creation of an environment where the level of global oil and gas prices is structurally lower than today. As a country that has been transformed over the last decade by the increase in hydrocarbon prices, Russia is extremely exposed to this development. Over the course of the last twelve years the level of Russia's GDP in dollar terms has increased nearly tenfold, driven by rising oil prices and a doubling of export volumes. Russia today is the word's largest producer and exporter of hydrocarbons, with production of nearly 10.5-m b/d of oil and 600-bcm of gas. Government spending has increased as the oil money has rolled in, and the government now required a level of $110 per barrel for the budget to breakeven in 2012. Direct taxes on oil and gas now make up 55% of the Federal budget and 25% of the total budget.

Figure 67. Russian fiscal break-even oil price, $/bbl



Source: MinFin, Citi Research

Figure 68. The Russian equity market and the oil price



Source: Datastream

Consequences of lower oil prices

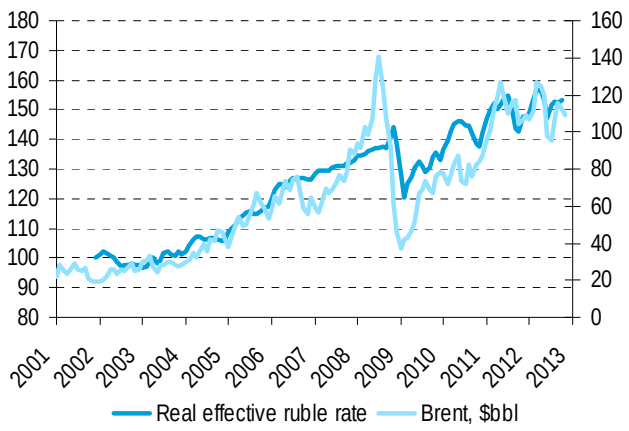
We divide the consequences of lower oil prices into four aspects: economics; profits; politics; and geopolitics.

Economics

We focus on three aspects of the economic story for Russia – the ruble, GDP growth, and macroeconomic stability. The ruble today has appreciated by over 60% in real terms against the dollar over the last decade, trades at 85% of PPP, and in real terms is the most expensive it has ever been; according to the Central Bank the real value of the ruble is 23% higher than at the start of 2008. The real value of the currency moves largely with the oil price, and therefore would fall in the event of lower oil prices. Although Russia can of course grow GDP at almost any oil price, that would need to come after a period of adjustment; at present the government estimates that GDP growth falls by around 1% for every $10 drop in the price of oil.

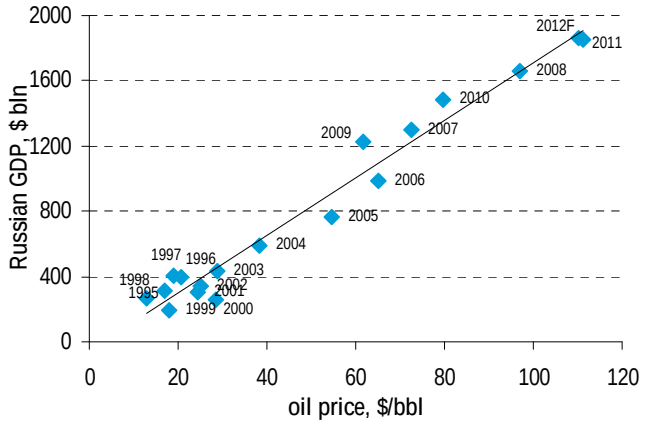
Thanks to a floating ruble and the reduction of debt during the good years, we do not believe that Russia has significant macroeconomic fragility provided oil prices remain over $80 a barrel. Government debt is under 10% of GDP, household debt is only 12% of GDP, and total foreign borrowing is 25% of GDP.

Figure 69. Real ruble and the oil price



Source: Datastream, Bank of Russia

Figure 70. Russian GDP versus the oil price



Source: Datastream

Profits

The Russian stock market is still dominated by oil and gas companies, which make up 55% of the index; thanks to the dependency of the ruble on the oil price, domestic stocks, for foreign investors, are also oil price-dependent. Consequently we calculate that the dollar profits of the RTS index fall by around 10% for every 10% drop in the oil price.

Politics

The winter of 2011-12 saw the largest protests against the Russian government since the 1990s, even when oil prices were still over $100. One response of the government was to make higher fiscal commitments, increasing its dependency on the oil price. Lower hydrocarbon prices would reduce the ability of the government to support its core constituency with the flow of easy money from oil. And in turn this might lead to a widening and escalation of protests against the regime. The response of the government, in an environment where it was becoming clear that it could no longer rely on oil money to meet spending commitments, is harder to predict. The optimist says that it would encourage liberalization and an improvement of the efficiency of government, while a pessimist would worry about systemic fragility.

Geopolitics

At present Russia is in its strongest economic position compared to Europe since the end of the Soviet Union and it has been able to exploit this strength by carving out a unique course and seeking to bring back its neighbors into its orbit.

However, lower oil pries would tend to reduce Russia's GDP and elevate that of China, meaning that the disparity between the two could move to levels not seen since the Middle Ages when China's GDP, according to Angus Maddison, was more than ten times bigger than that of Russia. Lower oil prices may also heighten tensions between Russia and its Muslim south. The consequence of both these developments would likely be to drive Russia into a more accommodating position with Europe.

The market

Although the Russian market prices in an oil price of around $70-80 already, in the event of a deterioration of oil prices we would expect the market to concentrate on the negative aspects thereof - a weaker ruble, lower profits, and more political uncertainty. This would likely drive the market to a lower level. Within the market the relative performance of the sectors depends on the speed in the change of oil prices. The rule of thumb in Russia remains that if the fall in commodity prices is slow and not dramatic, then investors should buy domestic companies, which benefit from still relatively high oil prices and also enjoy growth. And if the fall in oil prices is rapid, then oil and gas stocks tend to outperform because they are cheaper than the rest of the market and because they are helped by a weaker ruble.

The silver lining

The silver lining of North American energy independence and the subsequent reduction in global oil and gas prices that we believe would flow from this, is that this would start to release Russia from the curse of oil, opening up the opportunity for a government able to diversify away from oil and gas and integrate more with Europe.

Challenges and opportunities for China

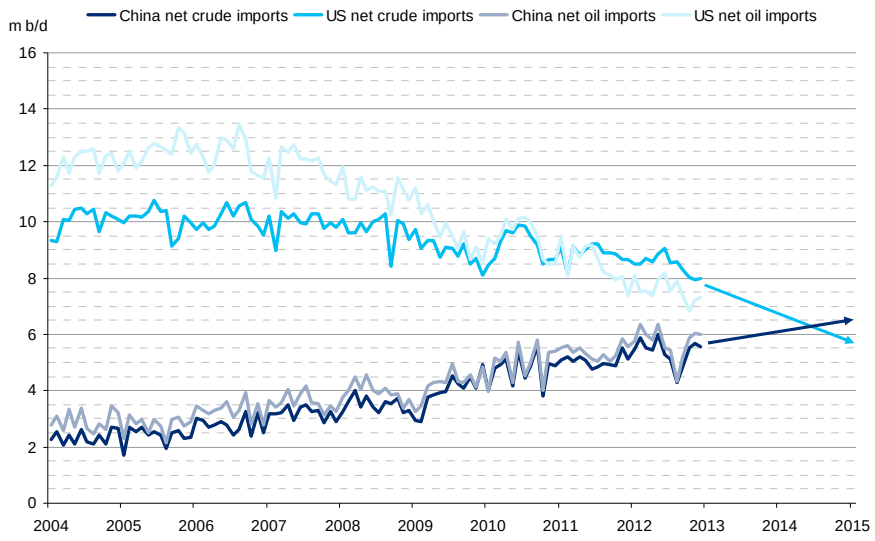
The North American supply revolution benefits the US relative to China, vis-à-vis energy security, and energy-intensive manufacturing competitiveness in relative terms

Easing global prices would benefit China in absolute terms, but not in relative terms vis-à-vis the US, particularly with regards to relative energy security. China could potentially see a better trade balance than it would in a world without the North American supply revolution. Globally, its balance of payments could become somewhat more balanced. But unlike North America, China looks still to be increasingly reliant on energy imports in the medium term, and would still require a diversification of its energy mix to help its energy security. Imports of all three of China's key energy sources – oil, gas and coal – should continue to grow unless economic growth slows much more then currently forecast. Therefore, energy remains a drag on the trade/current account balance. In 2020, Chinese oil imports could account for over 70% of consumption (up from ~55%), gas imports ~50% of consumption (up from ~25%, even including growth in unconventional gas), and coal imports should rise too.

Chinese energy demand growth outstrips its ability to produce more domestically, increasing its energy import dependence in oil, gas and coal; Chinese shale gas is a post-2020 phenomenon, but bear in mind that the resources are vast

Natural gas prices should continue to go up as the government raises regulated prices, which are on a rising trend in China. Refined petroleum product prices are basically in line with global prices right now (although there is some debate as to whether this would be the case if oil were to rise to over ~$120/bbl), but gas prices should continue to rise. Even if gas exports from North America eventually drive a breakdown in the oil-price link in the Asian contract LNG market, gas import prices, at least to 2020, should be driven by contacts already signed. Coal prices are also likely to rise as more coal comes from further west in China, and as lower grade deposits are exploited, domestic inflationary pressures continue (particularly labor) and safety and environmental issues become more prominent. Therefore, average energy pricing should continue to rise – because prices of at least two of the three key sources look set to rise, but also because a change in the energy mix drives higher average pricing; coal, the cheapest source, should account for a smaller percentage of the energy mix than the ~70% it makes up now.

Figure 71. Star-crossed: China's net oil imports are on the rise even as the US's plummet



Source: EIA, Citi Research

But falling international energy prices helps take the edge of all net energy importers, not least the largest of energy consumers in the world – China

Thus, there are challenges ahead for China in the energy sector, but easing global prices may at least take some of the edge off this. As global prices ease, imported inflation could be somewhat better contained; energy prices – along with food prices – are two of the key external drivers of Chinese inflation, which the Asian giant is keen to keep under control, for social stability reasons, as well as maintaining headroom for stimulative monetary policy. A less-tight policy stance would allow economic growth to benefit on both the consumption and investment side. And as China attempts to allow (controlled) domestic energy prices to rise and converge with the international level, easing global prices on the back of the North American supply revolution could help reduce somewhat the pain of adjustment. On the flip side, lower energy prices could also lower China's incentive to reduce its energy intensity and develop alternative sources within its energy mix.

North American manufacturing competitiveness is on the rise as domestic energy prices fall, but also as China's labor cost advantage erodes

On manufacturing, the impact of the North American supply revolution seems to be more dispersed, and may not be as much of a headline item compared to oil security itself, given that these industries are relatively less concentrated than the major oil and gas-producing national oil companies (NOCs). A number of industries are turning their attention back to the US and considering greenfield and brownfield developments there; this trend has been supported by three major factors: 1) lower energy and feedstock costs in the US; 2) the gradual erosion of the global labor arbitrage that previously made labor-intensive manufacturing overseas much more competitive; and 3) the closer proximity to demand centers and the improvement in supply-chain logistics. Other than the Middle East, the US broadly has the lowest energy costs globally. The petrochemical, fertilizer and other industrial sectors, as discussed earlier, are indeed planning to expand in the US. With slow global economic growth, this does take industries away from other regions, though the global game may not be completely zero-sum. Labor costs are also rising elsewhere. Those still with lower labor costs may not be able to scale-up as quickly, especially with less-developed infrastructure affecting logistical capabilities. Finally, transportation costs could remain a burden, particularly due to the rising cost of energy since the latter part of the decade. (The downward trajectory of global oil prices going forward is meaningful, with a $90 ceiling on prices in the long-term in our view, but this is still a good deal higher than the long-term deferred futures oil price of ~$21/bbl that prevailed with remarkable stability before the early-2000s, a

level to where front-month prices would mean-revert.) Hence, improved logistics could be critical in a more competitive environment where profit margins are increasingly squeezed.

While some are expecting that China may have to take on a greater role in geopolitical issues beyond its borders due to its heavy reliance on foreign energy sources, the country seems to be working to partly mitigate these by lowering its energy intensity, as mentioned. It also has regional disputes with neighboring countries, and with a military structured more for short-range engagements, it might seek to limit its involvement further afield.

Thus, it makes sense for China to look to reduce its energy intensity

China's desire to reduce its energy intensity is driven by three major factors, among others: 1) the supply and transit risk involved in the transport of oil, gas and coal; 2) national economic competitiveness, particularly in terms of energy intensity; and 3) environmental degradation.

- **Supply risk** – oil is especially vulnerable due to the need for extra long-haul transport, since China obtains a large portion of its oil from the Middle East, as well as Africa to the west and South America to the east. The entire route is exposed, perhaps even subject to, foreign intervention. These supplier countries also have their own political risks internally.
- **Energy intensity** – it is acknowledged that growing an economy of China's size at a high energy intensity level would not be sustainable. Higher energy prices raise the cost of production, especially when the labor advantage is receding at the same time. To sustain a still relatively high rate of economic growth, perhaps with the purpose of job creation and social stability in mind, energy intensity would have to fall. It is indeed falling, but helped by a number of measures. Besides the closures of some inefficient plants, China's massive building of nuclear reactors – now just under 20GW but projected to grow to around 60 to 70GW (though still less than the more ambitious 80 to 90GW) – is in part a way to reduce the country's reliance on fossil fuels.
- **Environmental degradation** – it is understood that China's breakneck growth to date has come at the expense of the environment. Besides water, the increases in emissions are eroding the substantial long-term endowment of the country. Deteriorating health and the spending needed to counter that could be a burden down the road, but so is the damage to land and water resources that are scarce already.

Geopolitical tensions on many fronts keep China's attentions occupied

Further, China is also facing geopolitical tensions closer to home that could divert some attention to issues elsewhere. Regional geopolitical tensions include the Diaoyu Island dispute on the eastern front with Japan, and in South China Sea with a number of ASEAN countries. The military appears to be structured to engage in short-range conflicts closer to its borders. China rolled out its first aircraft carrier in recent days to great internal media fanfare.

The pace and composition of Chinese demand growth is changing

Will Chinese – and Indian – demand growth offset the US supply surge? There are many misconceptions about the pace of demand growth in emerging markets, especially in China and India (although Indian demand growth has been far more muted than Chinese demand growth). The thrust of Chinese urbanization is diminishing and the Chinese population is aging quickly, pointing to a time in the not-too-distant future that demand for transportation fuels slackens. Additionally, the age of go-go infrastructure growth and subsidized energy intensive industrial growth is also ending. Projections based on false parallels either with the last decade or the experience of the US can be misleading.

Is the shale revolution replicable overseas?

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

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

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

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

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

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

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

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

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

Figure 72. The UK has significant shale resources, a history of production, and good understanding of its geology, but shale could still see a slower pace of uptake there

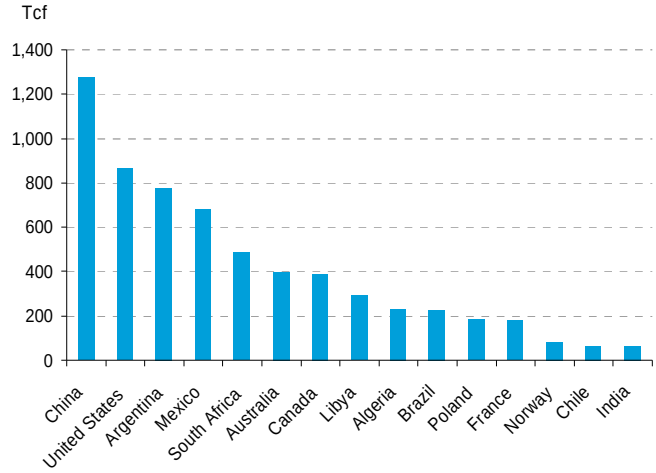
Source: FT, Citi Research

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

China has perhaps the largest shale gas resources outside the US – the EIA estimated 1,275-Tcf, though the Chinese Ministry for Land and Resources' own March 2012 survey sees a smaller but still-substantial 25 tcm (875-Tcf) – and while the government is targeting ambitious growth in shale development, exploration and development have been slow to date. Early indications suggest more challenging geology than that of the major US shale plays to date, against a background of acute water shortages in the most of the major Chinese shale resource areas. Limited experience with the technology and historically limited mapping of resources provide further drags, although this can be overcome. Also hindering the appetite for development is the lack of pipeline infrastructure to bring new supply to market, and new pipeline construction – and by extension, shale gas development – is not well

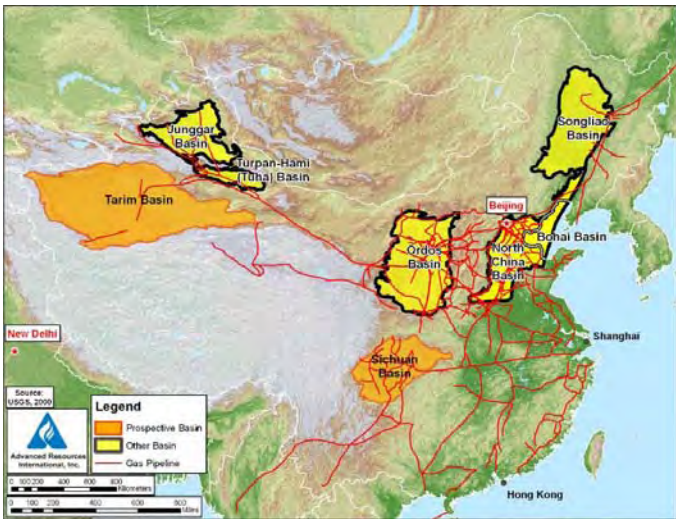
incentivized by low, government-controlled gas prices. A more restrictive environment for smaller, entrepreneurial independent-like companies could also inhibit the feverish activity and pace of growth seen in the US. For now, Chinese companies' strategies seem to be focusing on gaining domestic acreage, learning from abroad through partnership and acquisition, and waiting until the domestic price control regime becomes favorable.

Figure 73. Estimated global shale gas reserves (technically recoverable, Tcf)



Source: EIA, Citi Research

Figure 74. China shale resources map



Source: EIA, Citi Research

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

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

Figure 75. South American shale resources

Source: EIA

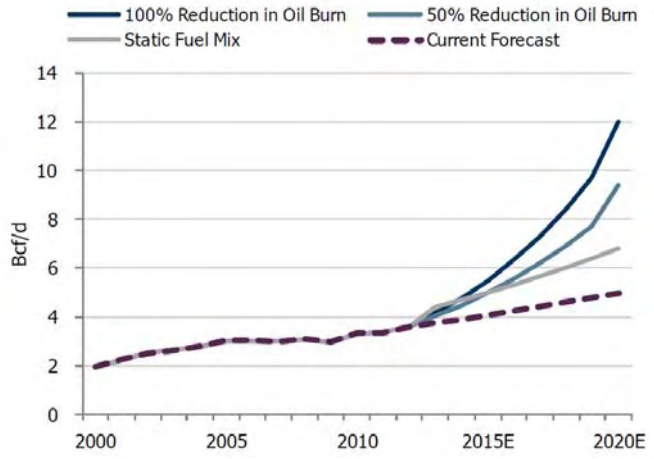
The EIA assessed Neuquen Basin to hold 407-Tcf of technically recoverable gas, which is twenty times the 21-Tcf estimated in the Eagle Ford play in the US. The Vaca Muerta shale formation may hold 22.8-bn boe of liquids. And international companies have continued to acquire acreage and drill exploratory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

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

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

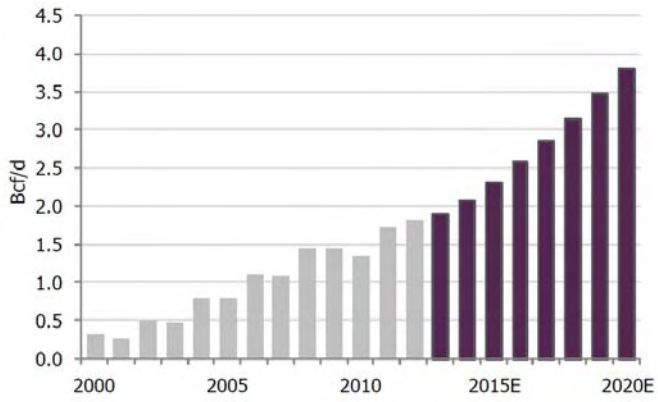
Poland and France have been identified as having shale gas resources, with the EIA assessing 187-Tcf in Poland and 180-Tcf in France, although the Polish Geological Institute has estimated a lower range of 346 bcm to 1.9 tcm (12- to 67-Tcf). Poland is keen to reduce its reliance on Russian gas, and does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

Figure 76. Saudi gas demand for power generation would be boosted if it boosted natural gas use in place of direct crude oil burn...



Source: PFC-Guggenheim

Figure 77. ...and natural gas use in the petrochemicals sector (estimates below) should see strong growth as well



Source: PFC-Guggenheim

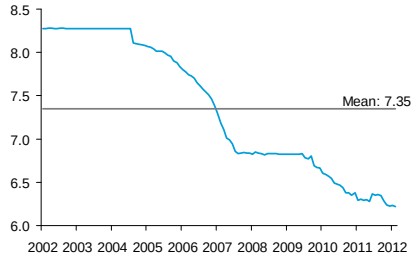
Energy 2020: Equity Analysis

A US energy-intensive industrial renaissance

Deane M Dray, CFA
Stan Fediuk

Citi's GPS report, "Energy 2020: North America, the New Middle East?", discussed the renaissance in energy-intensive industry that could come about in response to the new cornucopia of hydrocarbon resources in North America, leading to some of the lowest cost natural gas in the world. This is already happening and should accelerate going forward. The shale gas revolution in the US is a key driver, helped by other benefits of re-shoring to the US and specific company and regional US factors, as well as eroding China and emerging market advantages, as discussed by Citi Global Industrials analysts in "Is There a US Manufacturing Renaissance?" (Deane Dray et al, January 14, 2013).

Figure 78. USD-CNY exchange rate

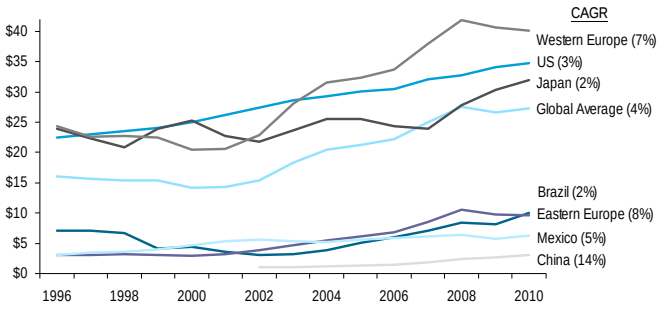


Source: Bloomberg, Citi Research

Wage inflation is particularly rampant in China, where it is rising faster than productivity, at 14% on an 8-year CAGR basis, though still among the lowest in the world at an eighth of the US's, and below Mexico, Eastern Europe and Brazil. The Chinese yuan has also strengthened, eroding the competitiveness of Chinese exports; it is expected to continuing an upward trend in the long-term as the Chinese economy continues to grow. And transportation costs to market, the risk of government intervention, concerns over quality control, and weak protection of intellectual property rights remain significant business risks in China.

Meanwhile, the US is still a leader in manufacturing productivity, when adjusted for inflation, and is increasingly above the global average. Combined with some of the lowest energy and feedstock prices in the world, this makes the US look like a more attractive proposition. However, Citi Global Industrial analysts do note that US corporate taxes – the second highest in the world at 35%, behind Japan at number one – are a drag, although state or local tax incentives help offset this.

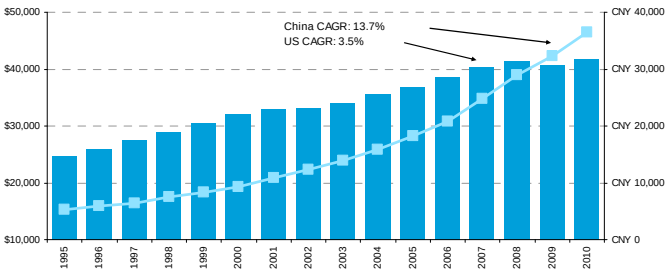
Figure 79. Global hourly manufacturing compensation in USD



Note: China's CAGR is over 8 years. All other listed CAGRs are for 14 years. The Global Average metric is an average of 19 developed and developing countries around the world.

Source: Citi Research

Figure 80. US versus China wage growth



Source: Social Security Administration, Citi Research

The natural gas boom has driven several recent domestic capital expenditure announcements by US chemicals and natural resources companies. What follows is an update of a number of sectors.

Figure 81. Recent US manufacturing facilities/expansions from Global Industrials companies

Companies	Facility Project	Location	Date Completed	Estimated Cost ($ mil)
Americas Companies				
3M	Research facility	Maplewood, MN	2015	$150
Caterpillar Inc.	Excavator facility expansion	Victoria, TX	2012	$70
	Skid Loader facility expansion	Clayton, NC	Began 2012	$33
Deere & Co.	Planter facility expansion	Moline, IL	2013	$58
	Engine cylinder facility expansion	Moline, IL	2013	$47
	Tractor facility expansion	Waterloo, IA	2013	$70
	Sprayer facility expansion	Des Moines, IA	2012	$85
Embraer	Bizjet production & customer center	Melbourne, FL	2011	$50
Emerson	Valve automation HQ	Houston, TX	Began 2012	$30
	Regulator technologies HQ	McKinney, TX	2013	$25
General Electric	Appliance Park	Louisville, KY	Feb-12	$800
	Aviation facility	Ellisville, MS	2013	$56
Illinois Tool Works	Technology center	Houston, TX	Jul-12	$1
SPX	Transformer facility	Waukesha, WI	Apr-12	$81
United Technologies	Otis manufacturing facility	Florence, SC	2Q 2012	-
European Companies				
Alstom	Gas and steam turbines	Chattanooga, TN	2010	$300
ABB	Cable factory	Huntersville, NC	2012	$90
EADS	Commercial aircraft final assembly	Mobile, AL	2016	$600
Rolls Royce	Aircraft engine/components plant	Crosspointe, VA	2011	$170
Siemens	Turbine/generator powergen plant	Charlotte, NC	2011	$350
Asian Companies				
Amada	Assembly facility & technical centre	Buena Park, CA	Oct-12	$50
Honda	HondaJet production facility	Greensboro, NC	2011	$60
	HondaJet MRO facility	Greensboro, NC	Summer 2013	$20
Kubota	Tractor assembly	Jefferson, GA	Jan-13	$73
Mazak Corporation	Machine tool assembly	Florence, KY	Late 2013	-
Mitsubishi Heavy Ind.	Gas turbine assembly	Savannah, GA	2012	$325
	Turbocharger assembly	Franklin, IA	2014	$15
Mori Seiki	Machine tool assembly facility	Davis, CA	Oct-12	$60
Shimadzu	Expansion of facility	Canby, OR	2012	$5

Source: Citi Research

Automotive

Automakers are currently expanding production in the US, and could possibly reap additional benefits from lower energy costs used in production and in supply chain component procurement benefiting from lower natural gas as a feedstock. Lower energy costs, especially natural gas, benefits automakers who produce in the US. Natural gas is a major feedstock for chemicals companies that produce plastics and other components used by the auto industry. Having manufacturing plants located closer to their suppliers also adds to savings. Although energy is a component of auto manufacturing, other factors also account for relocating to the US. For Japanese automakers, yen strength has been a factor. Having US-based production and sourcing benefits Japanese automakers and currently, 30-40% of car components are imported to US from Japan for Japanese carmakers.

Figure 82. USD-JPY exchange rate

Source: Bloomberg, Citi Research

Figure 83. Automobile incremental production increases by location

Company	Type of Expansion	Location	'13-'15 Incremental Unit Production	Energy
Daimler	Increased production	Tuscaloosa, AL	73,147	Power, gas
Fiat	Increased production	Toledo, OH	219,193	Power, gas
Ford Motor	Increased production	Louisville, KY	169,255	Power, gas
Ford Motor	Increased production	Flat Rock, MI	113,179	Power, gas
General Motors Co	Increased production	Detroit-Hamtramck	127,704	Power, gas
General Motors Co	Increased production	Wentzville, MO	116,678	Power, gas
General Motors Co	Increased production	Spring Hills, TN	90,373	Power, gas
Honda	Increased production	Lincoln, AL	80,687	Power, gas
Hyundai Motor	Greenfield facility	Montgomery, AL	149,654	Power, gas
Hyundai Motor	Increased production	West Point, GA	124,594	Power, gas
Nissan	Increased production	Smyrna, TN	229,203	Power, gas
Nissan	Increased production	Canton, MS	98,611	Power, gas
Volkswagen	Increased production	Chattanooga, TN	82,339	Power, gas

Source: HIS, Citi Research

Chemicals

Citi's chemicals analyst PJ Juvekar forecasts North American production growth in ethylene and ammonia. For the full report, please see "Many Ways to Play US "Shale Supremacy" – E&Cs the Next Big Thing?".

Ethylene

Why the US? – While the new capacity is small in the context of global ethylene market, the incremental capital is likely to flow to the US given that: 1) the US has a surplus of NGLs, particularly ethane, which is currently being rejected; 2) the Middle East seems to be running out of cheap gas, particularly in Saudi Arabia, and the region is building out naphtha plants as a result (for more details please see "Insights from the Middle East - Arab Spring Changes Strategy for Middle East Chemical Players"); and 3) the US has the best infrastructure of pipelines, storage, and power which translates to attractive returns for new plants on the Gulf Coast.

Figure 84. Announced US ethylene expansions

Company	Type of Expansion	Location	Capacity (MM lbs)	Startup Year	Comments
CP Chemical	Greenfield	Cedar Bayou, TX	3,300	2017	
Dow Chemical	Greenfield	Freeport, TX	3,300	2017	
Dow Chemical	Brownfield	Taft, LA	850	2013	
ExxonMobil	Greenfield	Baytown, TX	3,300	2016	Startup likely to be delayed to 2017 or later
Formosa Plastics	Greenfield	Point Comfort, TX	2,300	2016	Startup likely to be delayed to 2017 or later
Indorama Venture	Greenfield	Not disclosed	2,860	2018	
LyondellBasell	Brownfield	La Porte, TX	850	2014	
LyondellBasell	De-bottleneck	Morris, IL/ Clinton, IA	100	2013	
Oxy/Mexichem	Greenfield	Ingleside, TX	1,197	2016	Startup likely to be delaytd to 2017 or later
RD Shell	Greenfield	Monaca, PA	2,500	2018	
Sasol	Greenfield	Lake Charles, LA	3,300	2018	
Westlake	De-bottleneck	Lake Charles, LA	235	2013	Feedstock flexibility
Westlake	De-bottleneck	Lake Charles, LA	235	2015	
Westlake	De-bottleneck	Calvert City, KY	180	2014	Feedstock flexibility
Williams Cos	Brownfield	Geismarl, LA	600	2014	

Source: Company reports, Citi Research

Ammonia

Ammonia is "coming back from the dead" after several plants were closed over the past 5-10 years following elevated natural gas prices from 2005-2008. However, just like the major petrochemical producers, the North American ammonia industry is poised to significantly increase capacity over the next decade. Many of the same fundamental drivers which are supporting the ethylene expansion — mainly cheap feedstocks due to the "shale supremacy" — are supporting the fertilizer industry's desire to increase ammonia capacity. But the primary difference with ethylene is that the end product will be entirely consumed in North America since the region is structurally short nitrogen fertilizers like ammonia and urea.

Recall that 60-80% of the cash cost of producing ammonia (a fertilizer for direct application and the feedstock for other products like urea, UAN, AN, etc) is directly related to natural gas costs.

Despite its high reliance on natural gas, the fertilizer industry was slower to announce new greenfield projects than the ethylene industry in response to cheaper natural gas prices. While the pace of ammonia project announcements has accelerated (at least 15 projects have been proposed by our count), we think the nitrogen players are generally behind the ethylene producers in finalizing permitting, finishing feasibility studies, and in some cases, securing capital. These delays may amplify the push for engineering talent during the 2014-2017 timeframe as both the ammonia and ethylene build-out happen at the same time. Plus, unlike a majority of the ethylene projects, several of the proposed ammonia plants are supported by farmer cooperatives or new entrants to the market and may not have the same access to capital compared to established players.

Figure 85. North American ammonia capacity outlook

Company	Location	Type	2012	2013	2014	2015	2016	2017	2018	2019	2020
Projects - New Sites											
Agrium	US Cornbelt							750			
CHS	Jamestown, ND						750				
Farmers of N. America	*Canada*										
IFFCO	Quebec, Canada							750			
ND Corn Growers Assoc	*ND or MN*										
Ohio Valley Resources	Spencer County, IN						800				
Orascom Construction	Lee County, IA					750					
Summit Power Group	Odessa, TX						370				
US Nitrogen	Greeneville, TN				60						
Midwest Fertilizer Corp	*Indiana*										
Projects - Existing Sites											
CF Industries	Donaldsonville, LA						1,156				
CF Industries	Port Neal, IA						770				
Incitec Pivot	Waggaman, LA						750				
Mosaic	St James Parish, LA						730				
Yara	Belle Plaine, Canada						750				
Debottlenecks / Brownfields / Restarts											
Agrium	Redwater, Alberta	Brownfield				100					
Agrium	Borger, TX	Brownfield					120				
CF Industries	Donaldsonville, LA	Debottleneck		91							
Koch Fertilizer	*Various*										
Orascom Construction	Beaumont, TX	Restart	250								
Potash Corp	Geismar, LA	Restart		480							
Rentech	East Dubuque, IL	Brownfield			63						
Mosaic	*St James Parish, LA*	*Debottleneck*					*270*				
Incremental Capacity Increase			**250**	**571**	**123**	**850**	**6,466**	**1,500**	**0**	**0**	**0**
Total North America Namplate Capacity			16,601	17,172	17,295	18,145	24,611	26,111	26,111	26,111	26,111
% of North American Capacity			*1.5%*	*3.3%*	*0.7%*	*4.7%*	*26.3%*	*5.7%*	*0.0%*	*0.0%*	*0.0%*
Total Ex NA Nameplate Capacity			197,195	210,284	215,360	222,159	228,777	232,315	234,249	234,472	234,471
Adjusted Global Nameplate Capacity			213,796	227,456	232,655	240,304	253,388	258,426	260,360	260,583	260,582
% of Global Capacity			*0.1%*	*0.3%*	*0.1%*	*0.4%*	*2.6%*	*0.6%*	*0.0%*	*0.0%*	*0.0%*
Memo: NA Ammonia Demand			*21,360*	*21,350*	*21,550*	*21,755*	*24,000*	*25,865*	*26,480*	*26,660*	*26,790*
Surplus / (Deficit)			*(4,759)*	*(4,178)*	*(4,255)*	*(3,610)*	*611*	*246*	*(369)*	*(549)*	*(679)*

Source: Company reports, Citi Research

*Projects in italics do not have enough public information to be included in our S&D model. The Mosaic project has not been officially announced but Citi Research believes there is a significant likelihood of completion

Metals and Mining

The surge in the North American oil and gas upstream sector has directly benefited steel demand for tubular goods, as drilling rigs rose to a peak of 2,026 in November 2011, before dropping back to 1,761 recently. As manufacturing moves back to the US, indirect impacts to construction, automotive and machinery should have an effect too, though harder to quantify.

Nucor is currently constructing a Direct Reduced Iron (DRI) facility in Convent, Louisiana with a projected start up in mid-2013. A DRI uses natural gas and non-coking coal vs. a traditional blast furnace that uses coking coal. DRI is primarily used on scrap metal to convert into pellets or briquettes that contain 90-97% pure iron. The Convent facility will be able to provide 6-7 million tons per year of low cost, high quality iron units. Nucor may also build additional DRI capacity, which would further boost natural gas usage.

To secure natural gas, Nucor entered into a long-term agreement with Encana Oil and Gas. Nucor will pay its share of cost and carried interest to ensure a sustainable competitive advantage in natural gas costs for the future.

US Steel has mentioned construction of a DRI plant in the future, but has not provided any guidance. Along with AK Steel, they have added natural gas injectors into blast furnaces, which reduces the usage of higher cost coke. Cost saving from this project is an estimated $5-10 per tonne.

Haul trucks in the sector are seeing conversions to LNG fuel use, with Caterpillar working with Westport for off-highway solutions. Meanwhile, the coal mining sector is also reportedly testing LNG haul trucks.

Figure 86. Selected new US metals and mining projects

Company	Type of Project	Location	Capacity (Mt)	Startup Year
Nucor	Direct Reduced Iron (DRI) facility	Convent, LA	7-Jun	2013
US Steel Corp	Direct Reduced Iron (DRI) facility	NA	NA	NA

Source: Citi Research

Transportation

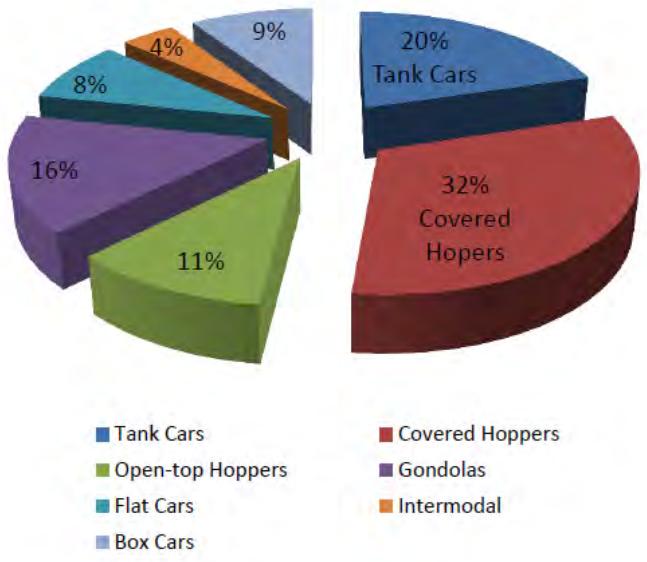
Due to the current lack of pipeline infrastructure to move Canadian crude and Bakken crude to the Gulf Coast, the rail sector is selectively capitalizing by shipping crude to the US Gulf, East and West Coast markets, as well as to eastern Canada. As the massive pipeline build-out in 2013 continues, connecting Cushing to the Gulf Coast, rails should see some pullback from this route. Rail companies now should not want to invest in shipping to the Gulf Coast, but focus on going east and west. But broadly speaking, the underlying growth in US production should continue to put pressure on infrastructure over time, meaning rail should continue to play a key rebalancing role in transporting new production to markets going forward.

The movement of crude oil by rail has grown significantly (see earlier discussion in Part I), driving surging demand for railcars, leading to backlogs in orders. In addition to tank railcars moving shale oil, hopper railcar use has also been increasing to transport fracking sand and other materials necessary for the shale oil production. As the shale gas – and oil – revolution continues apace, the petrochemicals sector has burgeoned again, and demand for tank railcars to transport chemicals has also risen.

American Railcar Industries (ARII) mentioned in its 3Q'12 conference call that the industry backlog for railcars at the end of September 2012 stood at 61,400 railcars, of which 87% were for tank and hopper railcars; the freight railcar industry backlog as of June 30, 2012 showed that 72% were tank cars. Their forecast for North America was for new railcar deliveries of around 58,000 for 2012 and 53,000 for 2013.

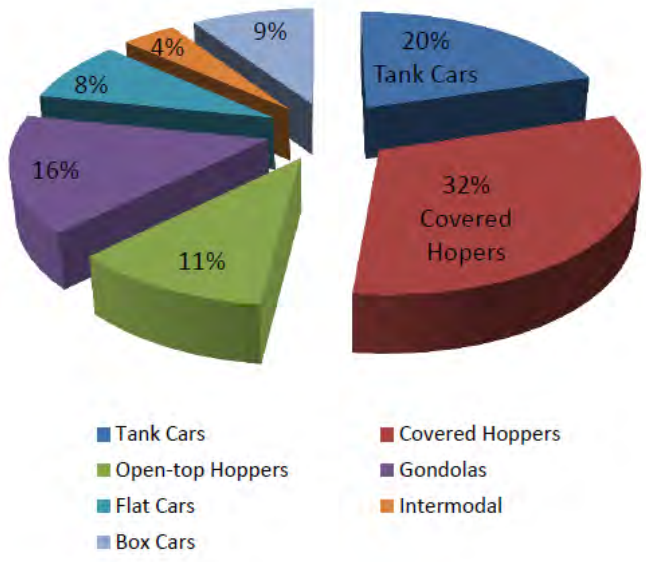
Tank railcars are the dominant type of railcar driving orders in North America. These railcars transport chemicals, propane ethanol, asphalt, corn syrup and crude oil. In 3Q'12, the industry reported that around 4,500 tank railcars were delivered, while 8,800 tank rails had been ordered. Around 46,700 tank railcars were backlogged at the end of September 2012, or over 75% of the industry backlog.

Figure 87. North American railcar fleet by type as of end-Dec 2011



Source: ARII Company Reports, Citi Research

Figure 88. Railcar backlog as of end-June 2012



Source: ARII Company Reports, RSI Reporting Statistics, Citi Research

Trinity Industries, in a 3Q'12 conference call, reiterated that railcar demand has been driven by oil and gas production activity as well as expansion in petrochemicals. Trinity also stated that a number of refiners and exploration production companies were purchasing railcars. However, demand for railcars to support the fracking industry as well as cement and other construction materials were a little slower than past quarters, though a recovery in fracking activity was expected in 2H'13; higher natural gas prices would also boost a recovery. The backlog for railcar orders was reportedly as long as 18 months. And though the past year has focused on the growth of railcar use for crude oil, the momentum of tank car orders is shifting from petroleum to the chemicals sector. Trinity Industries reports increased movement of petroleum and chemical products, with tank barge orders as far out as to 2014.

Hopper railcars are the largest product segment of new shipments although ARII sees slowing orders for hoppers. These railcars carry plastic pellets, grain, cement, fracking sand, food service and potash. ARII states there are interest in covered hopper rail types that carry plastics, potash and soda ash.

Figure 89. US-based railcar manufacturing

Company	Production	Location
American Railcar	Covered Hoppers	Paragould, AR
American Railcar	Tank cars and covered hoppers	Marmaduke, AR
Trinity Industries	Tank cars and hoppers	Southern US
Grenbrier	Railcar manufacturing	Portland, OR

Source: Company reports, Citi Research

Machinery

Cummins

Cummins Inc. this year began development of a 15-liter heavy-duty, spark-ignited natural gas engine for the North American truck market to be available in late 2014 on a limited basis, and beginning full production in 2015. Cummins is also producing on-highway spark-ignited natural gas engines under Cummins Westport, a joint venture with Westport Innovations in Vancouver, British Columbia. The JV currently produces B Gas Plus six cylinder, C Gas Plus 8.3 liter and ISL G 8.9 liter engines. In 2013, the JV plans to produce ISX12 G 12 liter engines. Cummings estimates a 5% to 10% industry conversion rate from diesel to natural gas over the next 5 to 10 years. The company also produces engines used in the fracking process.

Figure 90. Natural gas engines

Company	Type of Project	Location	Startup Year	Comment
Cummins Inc	15-liter natural gas engine	Whitakers (Rocky Mount), NC	2014	Cummins will produce 15-liter in 2014
Cummins Westport JV	6.7, 9 and 12-liter natural gas engines	Jamestown (Lakewood), NY Whitakers (Rocky Mount), NC	Now	Produces natural gas power engines in 6.7 and 9-liter

Source: Company reports, Citi Research

CONCLUSION

What does this all mean?

Edward L. Morse
Head of Global Commodities Research

The North American supply revolution has many impacts, and there are winners and losers in the process

Briefly, there are significant benefits from the revolution in unconventional oil, particularly for the economies where this revolution is unfolding, whether in the US and Canada, or Mexico and Brazil, Colombia and Argentina in the Western Hemisphere, but the countries in West and East Africa where there are significant new finds of hydrocarbons in deep waters. It remains to be seen whether Europe is able to overcome the obstacles now confronting shale exploitation, but the countries of the Eastern Mediterranean are just beginning to see the promise of deepwater finds in Israel, Cyprus and offshore Gaza. There is plenty of promise from South Africa to East Asia, and China's potential both in onshore shale and in territorial deep waters may help the country eventually limit its dependence on foreign supply.

Net energy consumers as well are likely to see significant gains if there is constant pressure on oil prices. Consider, for example, the effects of a $20 drop in prevailing oil prices globally. At current production levels, that amounts to some $1.7 billion per day for the world as a whole, or an annualized $620 billion globally. That amounts to a great deal of effective "quantitative easing", with widespread transfers from oil producers to consumers.

But there is another side to this, both with respect to producing companies and producing countries. For producing companies, otherwise losers, there are offsets – production costs are also under secular downward pressures; tax systems shelter companies significantly from the adjustment requirements to lower prices; and large integrated companies can benefit in other ways, with for example, lower petrochemical feedstocks and expanding petrochemical production.

There is an increasingly zero-sum aspect to unfolding market dynamics and their geopolitical impacts for oil and gas

But when it comes to governments, in the geopolitics of oil and gas, there is an increasingly zero-sum aspect to unfolding market dynamics**.** Unconventional oil, whether from deep water, or oil sands or tight oil, requires a high price – perhaps $70 per barrel to be sustainable and, if history is any guide, technological and market changes ahead to bring costs down. Conventional OPEC production on the other hand requires $100 per barrel today, not on a cost of production basis, but on a budgetary break-even basis, with a higher and higher number going forward.

The market outlook is pointing to a shift in the trading range for oil, whereby the bottom of today's trading range ($90-$120/bbl) is going to be the top of the likely trading range by 2020 ($80-90). That's a recipe for confrontation, for increased domestic turbulence in oil producers, rather than a recipe for producer-consumer agreement.

OPEC as a cartel faces increasing challenges to its coherence, which may help ease oil prices, but could exacerbate political instability within and between member countries

When it comes to OPEC countries, the issue should be a combination of internal and external issues and the relationships between them. Will there be surplus capacity members of the producer group? If not, then the issue is clear – OPEC members should try to enhance production in order to enhance revenue, because the politics of production restraint should exacerbate the free rider problem that already exists – how easy will it be for GCC countries to agree to pull back on output, not knowing whether the others will follow? If there are surplus capacity members of the group, to what extent will they be willing to "punish" the peripheral members of the producer group by bringing prices down, when their own fiscal requirements for revenue are also growing? If the main picture is one of diminishing surplus capacities and therefore declining clout for OPEC's leader to be able to

discipline other members into accepting quotas by increasing output unilaterally then the question is whether market forces allow them to produce all out without precipitating a price collapse.

Prospects for a fruitful International Energy Forum (IEF) dialogue between producers and consumers also look fairly bleak in the new market environment. Talk will likely continue, but action is likely to be even more difficult than it has been. It wasn't so long ago the large importing and exporting countries and the CEOs of some major oil companies were rejoicing of a new golden age of a goldilocks price in the $70 range. That didn't last long.

New challenges arise for global energy governance, such as the issue of strategic reserves, given new supply, demand and trade flows and trends

As for the IEA, there would be a new set of structural elements that would weigh heavily. On the one hand, the question is how would the emerging market importers – China and India, in effect – access their ties as importers to the US and Europe and Japan. The chances are, as US import requirements fall annually, they should have more incentives to cooperate rather than fewer, but this is not clear and is an area for considerable investigation. On the other hand, there are two tangible elements of US policies toward its Strategic Petroleum Reserve that appear to become significant issues of public debate.

First, what are the ways strategic stocks should be used under changing circumstances? The two most recent supply disruptions – Libya due to internal strife and Iran due to international sanctions – are critical fodder for this debate. So too are the difficulties of using a crude-only strategic supply when the problems emerging in recent years from weather conditions or refining shortfalls have been in the area of products rather than crude oil. It is instructive that the one use of the Northeast Heating Oil reserve came this year in the aftermath of Hurricane Sandy, when stocks were released to provide diesel transportation fuel.

Second, what is the right level and composition for the US Strategic Petroleum Reserve and where should it be located? Trends are pointing to a need for 1) much less oil; 2) much less light and sweet crude, at least today, and much less heavier and more sour crude tomorrow; 3) much less crude on the US Gulf Coast and some crude on both the US West and East Coasts; and 4) more product in the mix. In short, a lower level of strategic stocks would impact global markets, impact relationships within the IEA, affect OPEC and affect an international dialogue.

Any way one looks at these issues, it is a Luddite view of change to assert that what's unfolding in North America is not relevant. The consequences are significant for markets, for the security interests of the US, for American foreign policy, for the geopolitics of oil, and for the world economy.

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Key Insights on North American Energy Independence

GLOBAL REACH

With heavy reliance on imported oil, the US is susceptible to oil disruptions that can lead to price volatility and shortages. / Although it won't eliminate oil disruptions, surplus export oil capacity is a protective force as exports can be reduced by government policy in the eventuality of a global supply disruption as a means of insulating the economy from some of the severe effects of higher prices.

POLICY

The current export control regime in the US dates to the 1970s in the wake of the Arab oil embargo and requires the President to restrict exports of US-produced crude oil. / Given the emergence of a crude glut within North America and given the US – including Canadian supply – could even move to a surplus by 2020, changes in crude oil export rules could be in store as well as a review of the Jones Act on shipping.

SOCIAL CONSTRUCTS

Many oil producing countries have high dependence on oil and gas production and growing spending requirements have pushed them to require higher and higher fiscal break-even prices for their oil and natural gas exports. / The market outlook is pointing to a shift in the trading range for oil whereby the bottom of today's trading range ($90-$120/bbl) is going to be the top of the likely trading range in 2020 ($70-$90/bbl), which could lead to increased domestic turbulence in oil producers.