ENERGY 2020: OUT OF AMERICA

The Rapid Rise of the United States as a Global Energy Superpower

Citi GPS: Global Perspectives & Solutions

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ENERGY 2020: OUT OF AMERICA

The Rapid Rise of the United States as a Global Energy Superpower

Edward L Morse
Global Head of Commodities Research

When it comes to crude oil and other hydrocarbons, the US is bursting at the seams. This situation is unlikely to stop even if prevailing prices for oil fall significantly – Citi anticipates that even if West Texas Intermediate (WTI) prices fell below $75 for a while, production growth would continue at relatively high levels for years to come. While the debate in the United States intensifies over whether the country should export crude oil, facts on the ground are mushrooming significantly faster than policymakers in Washington recognize or global markets are ready to realize.

As of today, every barrel of locally produced petroleum product and crude oil – as well as the as-yet-to-be-defined category of condensate — that can get out of the country is in fact getting out. Too much attention has perhaps been placed on whether to lift the 'ban' on crude oil exports. There really is only a limited legal ban effectively impacting only oil produced in federal waters or transported through a federally mandated pipeline; elsewhere there is a minefield of obstacles but also a fairly permissive regulatory framework that already applies to Canada, is likely to be applied within a year to Mexico, and soon thereafter to some free trade agreement partners, even without legislation to lift the ban.

The US has very rapidly become a powerhouse as an exporter of finished petroleum products, natural gas liquids, "other oils" including ethanol, and – yes – even crude oil – with total gross exports expected to reach a combined 5-million barrels per day (m b/d) or more by the end of this year, up a stunning 4-m b/d since 2005. Mid-year 2014 combined hydrocarbon exports of 4.5-m b/d already pushed total oil exports to the top of the list of US exports by category, far surpassing all agricultural products, capital goods and even aircraft as the largest sector of US export trade. Meanwhile, US crude oil exports, largely to Canada, are 500% above what they were a year before, and are heading for around 500,000 barrels per day (500-k b/d) by year end.

Citi fully expects that allowable exports of crude oil and condensates – a special category of light crude oil – will exceed 1-m b/d gross by early 2015 if not before. Exports to Eastern Canada are marching toward a half a million barrels a day, and we expect renewed exports from Alaska to grow to a higher, steadier state of above 100-k b/d, for exports to Mexico to begin to materialize at least under an exchange program and to grow possibly to well over 200-k b/d, for allowable exports of processed condensate to reach 200-k b/d or more before long, and for re-exports of Canadian crude oil entering the US by both pipeline and rail to reach a similar level. Already the US exports more crude oil than OPEC member Ecuador, but that still opens the question of "net" exports.

The US has reduced its net oil imports by a stunning 8.7-m b/d over a very short period of time – that's more than the total production of all countries in the world other than the US, Russia and Saudi Arabia and also greater than the combined exports of Saudi Arabia and Nigeria. Eight years ago, in August 2006, the US imported, net, a little over 13.4-m b/d of crude and products; recently the net import number has fallen to 4.7-m b/d at the end of 1H 2014.

Citi expects that the oil import gap will be totally closed well before the end of the decade, possibly by 2019 if not by 2018, at which time the US should become a net exporter of crude oil and petroleum products combined. Meanwhile other exports are closing the total “hydrocarbon” import gap rapidly. Obstacles to crude oil exports have given rise to phenomenal growth in petroleum product exports.

Since 2010, the US moved from being the largest gross and net product importer (of gasoline, diesel, jet fuel and liquefied petroleum gas’ (LPGs) like propane) to the largest gross exporter and the second-largest net exporter next to Russia, which ended last year exporting 3.2-m b/d of products. By the end of 2016, the US could jump ahead of Russia as the largest supplier – net – of petroleum products in the world; by 2020, Citi estimates US net product exports could lie somewhere between 4.7- and 5.6-m b/d, somewhere between 1.3- and 2.2-m b/d higher than Russia at that time.

When it comes to LPGs like propane, butane and ethane, the US already overtook Saudi Arabia as the largest exporter more than a year ago. Within three or four years the US is likely to add more than 1-m b/d to these exports and alone should be exporting more LPGs than the entire Middle East, today’s base load supplier of these feed stocks to Asia and the rest of the world.

Then there’s natural gas. At the start of this decade, the US was a net importer of natural gas. By the end of the decade, exports by ship of Liquefied natural gas (LNG) should rival those of Qatar, the largest such exporter today, and pipeline exports to Mexico and Canada could be of the same magnitude, pitting the US against Russia as the number one or two natural gas-exporting country in the world.

Since the start of the ramp-up of Canadian and then later US production there has been a lag in infrastructure to get new production to domestic markets and get both product and crude oil to foreign markets. An enormous build-out of rail transportation for crude has resulted, bringing crude to pipelines, to refineries and to ports both within the United States and from Canada to the United States. Combined volumes have grown dramatically since 2010, rising from less than 50-k b/d to nearly 1-m b/d at the end of 2013. Despite the fact that pipeline transportation is far more efficient than transportation by rail, barge and truck, adequate investments are not being made in pipeline infrastructure and the rail system in particular is becoming congested and, after some major accidents, the subject of debates on improving rail safety.

The lag in pipeline infrastructure is part of a big chicken-and-egg problem. Most of the rail transportation comes from the Bakken where some 70% of production is shipped by rail, mostly to the East and West Coasts. Refiners on the US Gulf Coast do not need light sweet crude and indeed have a superabundance of it locally in the Eagle Ford and Permian Basin in Texas. But refiners on the two coasts are fearful that if they commit to use pipelines to transport the crude oil they need, they could end up in an unfavorable position economically if the US were to ease restrictions of exports. Similarly, companies and investors are unwilling to commit to build new refinery capacity lest the US government lift the export restrictions, impacting their feedstock costs.

Export capacity is constrained both because of congestion in the US Gulf of Mexico harbors and because of lack of investment, which itself is being held back because of uncertainty related to US export restrictions. So, even if export restrictions were to be relaxed significantly, it could take years to get the infrastructure in place.

In the end, there remains an inevitable day of reckoning when US crude production cannot escape its North American confines, pushing down US crude oil prices and endangering production, without widely liberalized exports. That day may be coming sooner than people expect, perhaps before the end of 2015. Meanwhile outcomes for production and export levels make a big difference – to the trade balance and to energy-intensive industries like fertilizers, petrochemicals and processed metals. This report explores some of the implications of these big differences.

The US government will inevitably need to respond to growing pressures to export crude oil. But the debates in Washington on whether to lift the various bans on exports of crude oil and condensate are misplaced. We do not anticipate a set of big debates in Congress or in the Administration to settle overnight issues related to changing the legislation on exports. By law, exports of crude oil produced in federal waters or from federal lands are banned, with some notable exceptions like exports from Alaska, from heavy oil in California and to Canada. It is unlikely that either of these laws will be changed any time soon. Other exports are placed on the Export Administration's short supply control list and in addition to crude oil, there are only two other commodities that are restricted from exports: unprocessed Western red cedar and horses exported by sea (but not by truck, train or airplane).

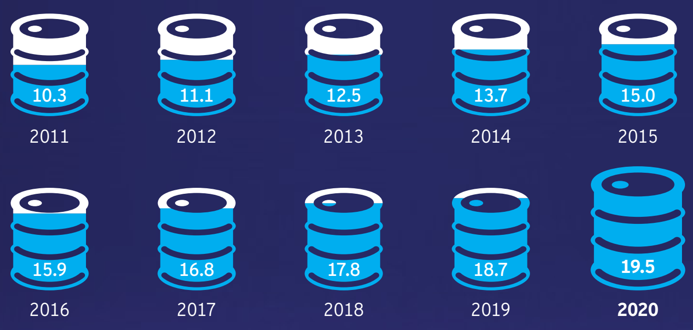
What is most likely to occur is the unfolding of a piecemeal, ad hoc set of decisions facilitating exports incrementally, with the sum of the increments reaching very high levels. There is unlikely to be a sudden change in the restrictive framework that limits crude oil exports from the United States. But progressive change is highly likely. The special conditions which now allow a significant volume of exports to Canada are undoubtedly being extended to Mexico. Both Canada and Mexico are Free Trade Agreement (FTA) partners of the United States and other FTA partners, including especially Chile, Israel, Singapore and the Republic of Korea are likely to petition for similar status. And eventually, restrictions on condensate exports, already reduced by recent decisions to allow processed condensate for export, are likely to be further eliminated with the development of a clear definition of what constitutes condensates. And meanwhile, exports from Alaska are likely to continue to grow in volume. The re-export of imported crude oil from Canada is also expected to grow significantly, soon to 200-k b/d and later to perhaps twice that level.

All of these details matter because they are shaping the emergence of North America as an energy superpower that is poised to usher in disruptive changes to global oil markets, trade, and investment. How this process unfolds is sure to create new winners and losers even as it remakes the global energy landscape.

The Closing of the Oil Import Gap

The US is bursting at the seams with crude oil and other hydrocarbons

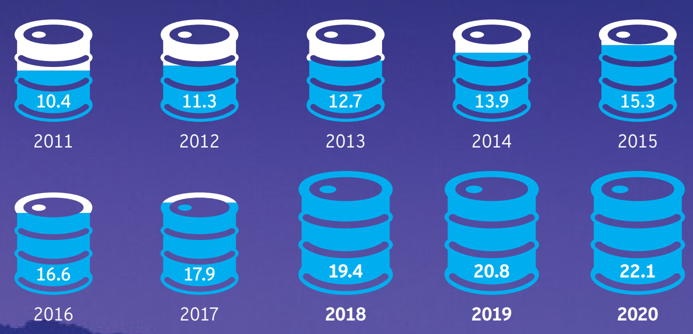
BASE CASE: U.S. BECOMES NET CRUDE AND PRODUCT EXPORTER IN 2020 (mb/d)



Total liquids demand
Total liquids production

Source: EIA, Citi Research

HIGH CASE: U.S. BECOMES NET CRUDE AND PRODUCT EXPORTER BY 2018 (mb/d)



Total liquids demand
Total liquids production

Source: EIA, Citi Research

EXPORT REVENUE FROM OIL AND GAS TRADE

Source: EIA, Citi Research

OVERALL U.S. CURRENT ACCOUNT DEFICIT

Source: Bloomberg, Citi Research

NATURAL GAS SUPPLY AND DEMAND TO BE UPENDED BY SHARPLY HIGHER US AND AUSTRALIAN GAS EXPORTS

Source: Citi Research

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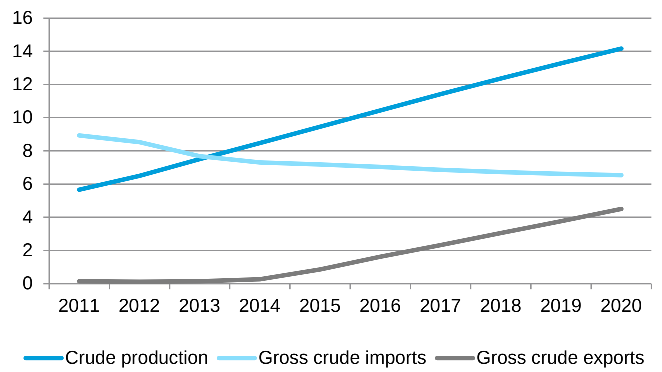
Energy 2020: Macro Analysis

Out of America: In a Nutshell

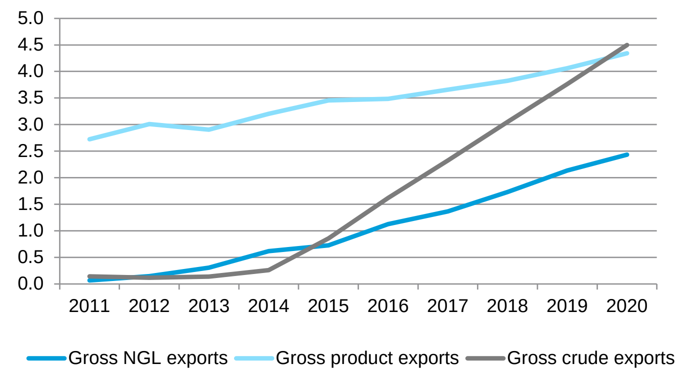
Production of hydrocarbons in the United States is mushrooming at a faster and more sustainable pace than even the most enthusiastic analysts had forecast only two years ago. Where exports are allowable they are surging, whether in the form of crude oil to Canada, re-exports of Canadian crude oil from the United States, pipeline exports of natural gas to Mexico (and a bit to Canada), or in the form of petroleum products, with massive impacts on the structure of global oil and gas trades. Along with these changes in the US trade balance are other transformations associated with the rise in production of energy intensive goods, especially fertilizers and petrochemicals, with similar dramatic impacts on US trade balances.

Figure 1. Rising US crude production could reach 14-m b/d in 2020 in a high case scenario, reduce imports and spur exports (m b/d)



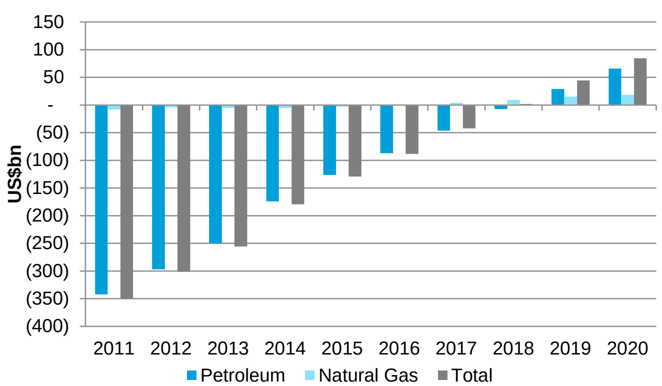
Source: EIA, Citi Research

Figure 2. Export of light crude should surge going into 2015, along with strong petroleum product and NGL exports (m b/d)



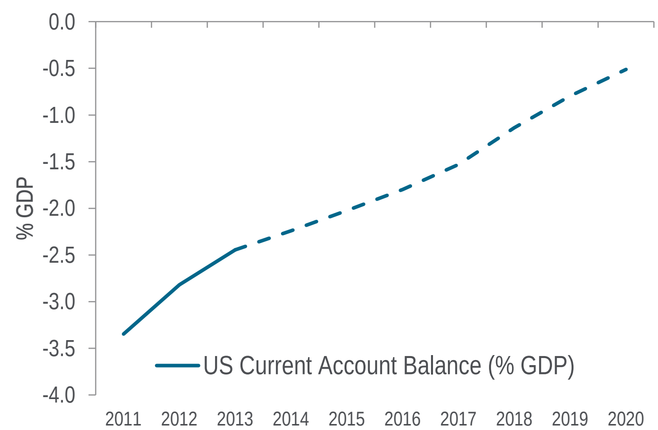
Source: EIA, Citi Research

Figure 3. The US oil/gas trade balance could go from a deficit of $354Bn in 2011 to breakeven as early as 2018, and a surplus of >$80Bn in 2020 due to net exports



Source: EIA, Citi Research

Figure 4. US current account balance (% GDP, 2011-2020E)



Source: Bloomberg, Citi Research

Over the past eight years, the US has moved from a peak level of net imports of just crude oil and petroleum products of over 13-m b/d to a net importer of around 5-m b/d at the end of last year. Citi projects in our base case that by 2020, total liquids supply will exceed total liquids demand in the US by some 950-k b/d, turning the US into a net exporter of crude oil and petroleum products. The balance in our projections is so close – with a mere 30-k b/d deficit projected by 2019, that the surplus could emerge even earlier, depending on how much the US moves toward a more facilitative approach to crude oil exports. If production at home is sustained at today's growth levels – which is higher than our base case – the US would become a net crude oil and product exporter of 700-k b/d by 2018, and by 2020 would be a net exporter of 3.6-m b/d.

Existing legal and regulatory restraints on exports would, in Citi's base case, result in a growing divergence between US and world oil prices, with US prices potentially falling low enough to slow down the pace of production growth based on increasingly tenuous economics of production imposed by obstacles to exporting US crude oil.

In our more robust case, as noted above, the US could become a net exporter of crude oil and petroleum products by as much as 3.6-m b/d by 2020 and the country could move to a net surplus of some 700-k b/d as early as 2018. Getting to that level would depend almost entirely on whether the US President and/or Congress opted for a more permissive crude oil export regime, which could occur even without the legal obstacles to exports being changed but rather with the President exercising his prerogatives in liberalizing the export regime.

Thus far the US and Canada have come a long way toward attaining a semblance of North American energy independence. Export growth of both crude and products from the US as well as increased exports from Canada to the US have had a tremendous impact on creating a crude oil surplus in the Atlantic Basin, softening the Brent/waterborne market by rejecting crude oil imports from third party countries to make room for burgeoning North American production. As recently as 2008, the US and Canada absorbed, combined, 2.6-m b/d of light sweet crude from other countries, and by mid-year 2014 those volumes shrank rapidly to no more than 500-k b/d and are expected to disappear completely from the North American trade balance by end-2015. This phenomenon is undoubtedly among the major factors behind the softness in the Brent oil market that emerged in summer 2014.

Already the push for exports of both US and Canadian crude oil is underway. By summer 2014 the US was exporting over 400-k b/d of crude oil to Canada, a more than five-fold rise over the comparable period in 2013 and a precursor of more to come. Meanwhile, Canada is settling in on ways to move crude both by rail and pipeline to the US, and by the start of next year, this total volume is expected to grow from about 2.6-m b/d in 2013 to close to 3-m b/d, with the dual impact of taking market share from other base load exporters to the US market and increasing Canadian barrels being re-exported out of the US. Citi anticipates that by the end of 2014 as much as 200-k b/d of Canadian crude oil imported into the US will be re-exported to other countries, and this volume could increase to 500-k b/d by the end of 2015.

The huge increases in US and Canadian production and the logistical restrictions on exports of Canadian crude anywhere other than the US and the legal restrictions on exports of US crude anywhere other than to Eastern Canada or from Alaska, have had a significant impact on product exports. With a totally liberal regime in place in the United States to export products, and

with dampened product demand in the US and surging production of natural gas liquids (which are treated as petroleum products), the supply pressures from within have pushed down crude oil prices in North America well below waterborne levels and led to a highly profitable growth in exports of petroleum products. The situation of having depressed US crude oil feedstock prices – and natural gas prices – has also led to what would otherwise be uneconomic growth in refining capacity in the United States along with the sudden change from unprofitable to highly profitable simpler East Coast (PADD I) refinery plants.

In just a few years, the US has been transformed from the world's largest gross and net importer of petroleum products (4.8-m b/d and 3.9-m b/d respectively at the peak month of October 2005) to the world's second-largest net exporter (2.5-m b/d end-2013), including natural gas liquids (NGLs). In Citi's base case, net petroleum product exports surge to 4.7-m b/d by 2020, making the US the world's largest exporter of petroleum products, a good 1-m b/d above Russia, which currently is the world's largest supplier of products. Of that, gross exports of 5.8-m b/d (including 1.6-m b/d of NGLs) more than compensate for gross imports of products of 1.1-m b/d, in contrast to end-2013 imports of 1.9-m b/d. In our more robust case, net product exports would reach 5.6-m b/d, with gross product exports of 6.8-m b/d (around the same level as current Saudi crude oil exports) and of that 2.4-m b/d would be LPGs. During this time, the US moves from its current position of exporting more LPGs than Saudi Arabia to exporting more LPGs than the entire Middle East, even in the base case, placing profound downward pressures on global LPG prices. US net product exports, in our more robust case, would exceed both total Japanese and German product demand today.

Pressures in the US market for exporting surplus crude oil and surplus petroleum products underlie the big debates under way in the United States today on whether eliminating or reducing the obstacles to crude oil exports are in the national interest. **The production growth in North America has been significantly faster than anyone could have imagined and projecting that growth forward indicates that the debates on crude oil exports will become a central feature of Washington politics within a year.** That's because within a few months, without export relief, crude oil prices in the US can become significantly unhinged from global markets. WTI crude oil could well be priced at $15-25 a barrel below Brent on a structurally "permanent" basis, and if Brent prices stay pressured at $90 per barrel levels, WTI could be priced below $70 or lower, putting significant pressure on production. This would put politicians in the position of having "killed the boom", providing a political counterweight to long-held fears that oil exports will lead to higher gasoline prices – the third rail of US politics.

Figure 5. US natural gas supply-demand

Natural Gas (Bcf/d)	2011	2015	2020
Gross Supply	68.6	77.4	96.8
Domestic Production	61.8	72.4	*91.4*
Imports (LNG)	1.0	0.1	0.0
Imports (Canada)	5.8	4.8	5.3
Total Demand + Exports	68.0	76.5	96.8
Industrials	18.9	21.7	26.1
Residential/Commercial	21.4	22.5	23.2
Electricity Generation	20.8	22.8	23.7
Pipe Use	1.8	2.0	2.4
Lease and Plant Fuel	3.7	4.0	4.6
Transport	-	0.3	2.3
Exports: Mexico	1.4	3.0	6.4
Exports: LNG		0.1	8.1

Source: EIA, Citi Research

US natural gas exports to Mexico are surging too, having risen by over 20% last year to average 1.9-Bcf/d. Going forward, they could rise by ~1-Bcf/d in 2015 and continue robustly, with upside potential. US exports to its southern neighbor have so far been constrained by (1) capacity in US-Mexico cross-border gas pipelines, (2) internal Mexican gas pipeline capacity and the distribution network, and (3) demand growth from gas-fired power plant expansions, as well as industrial demand. But improvements in natural gas infrastructure across the border and inside Mexico can alleviate this, with major steps in the fourth quarter of 2014 and first half of 2015.

Much more attention has been paid to LNG exports, though. Already, over 10.6-Bcf/d (80-Bcm/y) of LNG exports has been approved by the US Department of Energy, and **Citi sees the potential for LNG exports to grow from almost nothing in 2014 to 8.1-Bcf/d by 2020 (~83-Bcm/yr).**

Adding expected end-of-decade pipeline and LNG gross exports amounts to 148-Bcm/year of natural gas exports. That compares with Russia's 211-bcm/year in exports in 2013 and Qatar's 106-Bcm/year. On a net basis US gas exports would be lower, given persistent imports from Canada that Citi expects to average 5.3-Bcf/d (40-Bcm/y) in 2020, making net pipeline exports a more modest 1.1-Bcf/d (8.3-Bcm/y) by 2020. **Still, the US would start to rival Russia, Qatar and Australia among the export powerhouses, particularly of LNG**.

Momentum for LNG exports continues to build, as economic arguments and less skepticism over an abundance of shale gas have been joined by geopolitical designs, brought into focus by the crisis in Ukraine and the Russian annexation of the Crimea. Combined with Qatari and Australian LNG, there could be a global glut of LNG by the end of the decade, challenging oil indexation as the basis of LNG pricing. Equally if not more important, much of the US LNG offtake is by tolling arrangement and the US does not impose destination restrictions. From the outset, starting in late 2015, US LNG will almost inevitably serve as the basis of a strong spot market, as US exports surge to a level that can rival if not zoom past Qatar as the world's largest LNG supplier.

Burgeoning export volumes of US hydrocarbons can apply outsized pressures to global markets. For certain sectors, small volumes bring about big impacts: export volumes of natural gas, condensate and NGLs might be small in the context of domestic US oil and gas markets, or even the global oil market in the case of condensates, but these volumes are big in relation to their destination markets worldwide. This is why the exports of US hydrocarbons can have such outsized impact.

- **US LNG exports** could reach 8- to 10-Bcf/d in 2020, which is ~10% of the US gas market but **~20% of global LNG**;
- **US gas exports to Mexico** could reach ~6-Bcf/d in 2020, which is ~7% of the US market but **more than 50% of Mexican gas supply**;
- **US condensate production** could reach ~2-m b/d in 2020, with a naphtha content of ~1.6-m b/d, but global naphtha demand might only be ~8-m b/d, which **makes US-derived naphtha ~20% of the global market**, much more if slightly heavier oil (but still light in terms of global standard) were included. By comparison, the global oil market is a >90-m b/d market;
- **US LPG (propane-butane mix) export capacity** should reach ~1-m b/d by 2016, which is **~12% of global demand** by then.

Hence, the exports of field condensate (or effectively naphtha given the high naphtha content of condensate) and NGLs have far-reaching implications globally: from impacts on the global petrochemicals sector in particular, to the remaking of long-held pricing mechanisms, as well as on absolute crude oil and gasoline pricing. **What magnifies the impact of these exports even more is the inter-fuel competition between propane/butane (and possibly ethane, all components of NGLs) and naphtha, of which condensate has a very high concentration, fighting for space in the petrochemicals sector as input feedstocks.**

In this report, we outline an outlook for US oil and gas balances, tying together views on US hydrocarbons production, domestic demand, and the trajectory of evolving trade flows, and we then review their economic and political impacts.

See these related reports for more detail into these components of the balance:

- "Citi GPS Energy 2020: North America, the New Middle East?", the first report in the series on the US shale revolution, prospects for energy independence, and economic impacts.
- "Citi GPS Energy 2020: Independence Day", updating the picture of potential economic and geopolitical impacts of American energy self-sufficiency.
- "Citi GPS Energy 2020: Trucks, Trains and Automobiles" on natural gas use in the transportation sector, and how this could erode oil demand.
- "The New American (Gas) Century" on the impact of rising natural gas production on domestic sectors, global supply and demand, geopolitics and long-term pricing.
- "Mind the Gulf" and "Exit Strategies" on the evolution of North American crude price differentials as the refining and midstream sectors respond to the shale production boom in North America, and "The Abyss Stares Back" on the robustness of US shale oil production growth in the face of lower oil prices.

The following sections of this report take a deeper dive into the following: (1) The outlook for US crude oil, NGL and natural gas production growth; (2) evolving US demand for petroleum products and the increase in exportable surplus; (3) the US emerging as a global energy superpower with rising hydrocarbon exports; (4) downstream impact in the form of industrial and petrochemical demand and exports; (5) infrastructure for production and exports; and (6) macroeconomic implications for external balances and the US dollar.

Figure 6. Key US petroleum supply-demand estimates

	Base case 2011	2015	2020	High case 2011	2015	2020
Total liquids production	10.4	15.0	19.5	10.4	15.3	22.1
Crude production	5.7	9.4	12.5	5.7	9.5	14.2
NGL production	2.3	3.2	4.6	2.3	3.4	5.5
Biofuels production	0.9	1.0	1.0	0.9	1.0	1.0
Other	0.2	0.3	0.3	0.2	0.3	0.3
Refinery gains	1.1	1.1	1.1	1.1	1.1	1.1
Net crude imports	8.8	6.4	3.7	8.8	6.3	2.0
-> Crude imports	8.9	7.2	6.5	8.9	7.2	6.5
-> Crude exports	0.1	0.8	2.8	0.1	0.9	4.5
Net petroleum product imports	(0.2)	(2.6)	(4.7)	(0.2)	(2.8)	(5.6)
-> Product imports	2.6	1.4	1.1	2.6	1.4	1.1
-> Product exports	2.8	4.0	5.8	2.8	4.2	6.8
-> of which petroleum products	2.7	3.4	4.2	2.7	3.5	4.3
-> of which NGLs	0.1	0.6	1.6	0.1	0.7	2.4
Total liquids demand	18.9	18.8	18.5	18.9	18.8	18.5
Major product demand (gasoline,jet,distillate,resid)	14.5	14.3	13.4	14.5	14.3	13.4
-> Gasoline	8.7	8.5	7.9	8.7	8.5	7.9
-> Jet fuel	1.4	1.5	1.5	1.4	1.5	1.5
-> Distillates	3.9	4.0	3.6	3.9	4.0	3.6
-> Residual fuel oil	0.5	0.4	0.4	0.5	0.4	0.4
Total liquids supply	19.1	21.4	23.2	19.1	21.6	24.1
Total liquids demand	18.9	18.8	18.5	18.9	18.8	18.5
Net product exports	0.1	2.6	4.7	0.2	2.8	5.6
Net crude imports	8.8	6.4	3.7	8.8	6.3	2.0
Net petroleum (crude+products) imports (exports)	(8.7)	(3.8)	1.0	(8.6)	(3.5)	3.6
REFINERY SECTOR						
Refinery capacity	17.7	18.3	18.8	17.7	18.3	18.8
Petroleum supply (refinery output)	18.7	19.7	20.2	18.7	19.7	20.2
Gasoline	9.1	9.5	9.7	9.1	9.5	9.7
Jet fuel	1.4	1.5	1.6	1.4	1.5	1.6
Distillates	4.5	4.9	5.0	4.5	4.9	5.0
Residual fuel oil	0.5	0.5	0.5	0.5	0.5	0.5

Source: Citi Research

US Production Surge: A Windfall

Despite persistent doubts about the sustainability of shale gas and tight oil exploitation, facts on the ground keep surprising to the upside. The resource base is far more extensive than initially thought and the economics of production appear to be sustainable at significantly lower price levels than had been imagined a short half-decade ago.

Two issues now are paramount: How much can production grow if export constraints remain in place? How far can production increase in tandem with the reduction if not elimination of obstacles to export? In both cases learning by doing and technological change are on the side of higher output. Finally, how sustainable is this production, at such potentially high levels?

Production projections

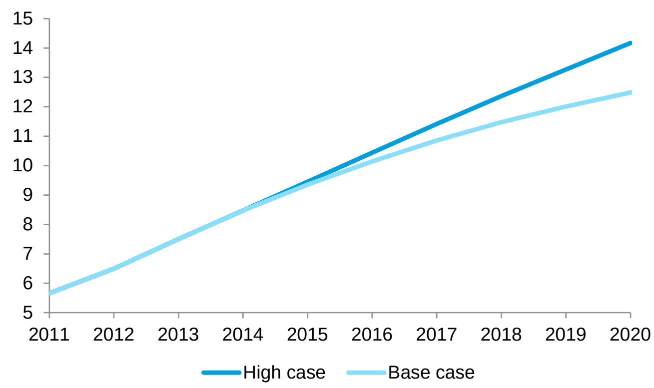
Surging crude oil production has already driven one round of glut and response over the 2011-14 period. This cycle was characterized by fast growing production in the Bakken shale play in North Dakota, as well as growing imports from Canada, which was delivered to the crude storage hub of Cushing, Oklahoma. Oil stockpiles there ballooned as takeaway capacity from Cushing and the Bakken was limited**; the price of WTI plummeted versus Brent** crude oil. US midcontinent refiners, with the windfall of lower crude prices, ran at searing utilization rates. **But it was only when new pipelines were built to join Cushing to the Gulf Coast (as well as divert crude oil from the Permian Basin in west Texas, also to the Gulf Coast) that bloated Cushing storage tanks were able to draw down stocks.** But now the glut moved to the coastal regions, and US crude exports faced legislative constraints.

Refineries have jumped on the opportunity to run cheaper crude, but a "crude wall" is coming; the new supply is overwhelmingly light, sweet crude, but Gulf Coast refineries prefer heavy, sour crude. Light, sweet crude imports have all but dwindled to practically zero, but incentivizing refiners to back out heavy sour crude imports would require light sweet crude prices to fall versus heavy sour crude prices to promote switching. In particular, some of this light, sweet crude is ultra-light, with API gravity levels well above 50 degrees. This is, in fact, condensate, and as a particular category of crude oil/hydrocarbon, may be treated differently in the way it is exported (see "Alert: US Condensate Exports").

US crude export policy has been the limiting factor, with growing awareness by the US government of the need to revisit this policy. But even as US crude oil production continues to grow robustly, Citi ultimately expects US crude export policy to loosen, allowing incrementally liberalized export flows. This would mean ultimately that US refineries stick to importing their preferred, heavier crude slate, while exporting newly produced light sweet crude oil. Currently, crude oil exports are already growing given current regulations, with allowable exports to Canada as the first area of expansion – for now. Going forward, even without legislative change, the US can export more Alaskan crude oil, exchange crude oil with Mexico, and export minimally processed condensates. With some regulatory easing, this could extend to crude exports to other FTA countries. Other than exports of US-origin crude oil, re-exports of foreign crude oil can rise too, particularly re-exports of Canadian crude oil transiting through the US.

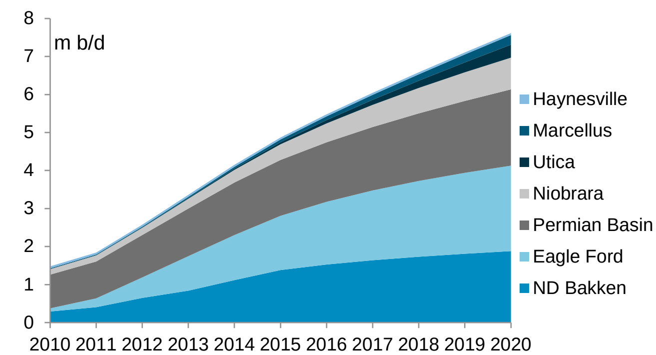
Oil production outlook at a glance

Figure 7. Citi's high and base case crude production (m b/d, 2011-2020E)



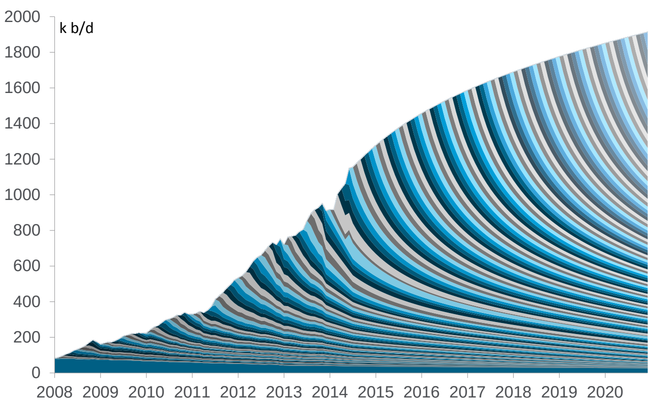
Source: EIA, Citi Research

Figure 8. US shale liquids outlook, base case (m b/d, 2010-2020E)



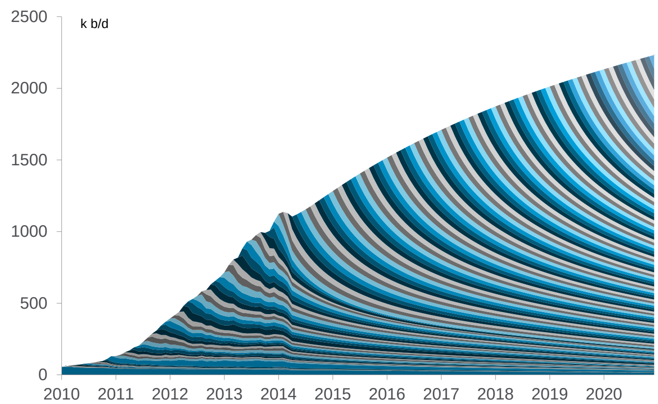
Source: EIA, Citi Research

Figure 9. North Dakota production outlook (kb/d, 2008-2020E)



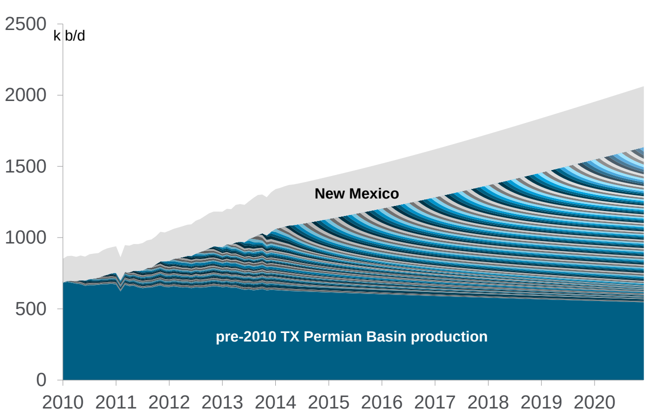
Source: EIA, Citi Research

Figure 10. Eagle Ford oil/liquids production outlook (k b/d, 2010-2020E)



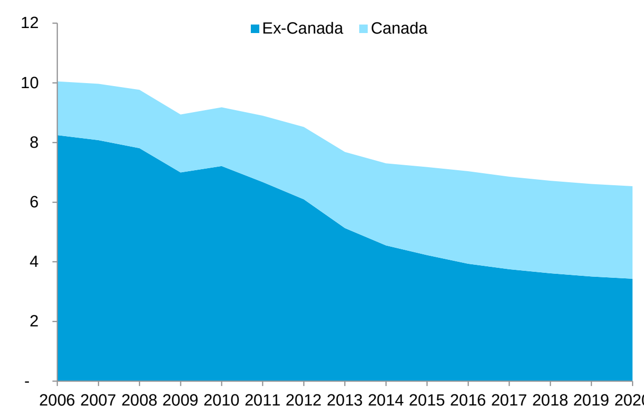
Source: EIA, Citi Research

Figure 11. Permian Basin oil/liquids production outlook (legacy, Texas and New Mexico, k b/d, 2010-2020E)



Source: EIA, Citi Research

Figure 12. US crude imports fall, and the shrinking pie sees Canada taking a larger share (m b/d, 2006-2020E)



Source: EIA, Citi Research

The two US oil production growth scenarios are shown here. The base case sees US crude oil production rising from 7.5-m b/d (of which 5.6-m b/d was onshore, 0.5-m b/d in Alaska, 1.4-m b/d was offshore) in 2013 to 12.5-m b/d (9.8-m b/d onshore L48, 2.3-m b/d offshore, 0.4-m b/d in Alaska) by 2020. In addition, NGLs production would rise from 2.8-m b/d in 2013 to 4.6-m b/d in 2020. This is based on limited productivity gains in shale production, with technological and process incremental innovations limited, or only offsetting deteriorating well productivity over time.

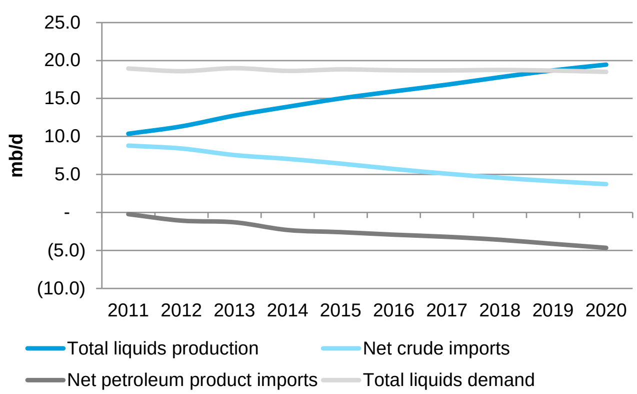
The high case sees US crude oil production rising from the same starting point of 7.5-m b/d in 2013 and rising to 14.2-m b/d (11.4-m b/d onshore L48, 2.3-m b/d offshore, 0.4-m b/d in Alaska) by 2020. In addition, NGLs production would rise from 2.8-m b/d in 2013 to 5.5-m b/d in 2020. The high case is based on ongoing, though diminishing, productivity gains in shale production.

Citi projects gross crude oil exports to grow to as high as 4.5-m b/d by 2020 in the high production case, which would mean net crude imports falling to 2-m b/d. Note that while the gross crude imports number looks likely to fall modestly to 6.5-m b/d by 2020 in both cases, its composition changes significantly – Canada makes up almost half, rising from 2.6-m b/d in 2013 to 3.1-m b/d**. Meanwhile growing petroleum product exports turn the US into a net oil exporter by the end of the decade (see below).**

This extends recent trends, with crude oil imports as high as 10.7-m b/d in June 2006, already down to 7-m b/d in June 2014. The rise in crude exports going forward is driven by crude production growth, which is projected to increase from 8.5-m b/d in 2014 to 12.5-m b/d by 2020 in the base case, and 14.2-m b/d in the high case.

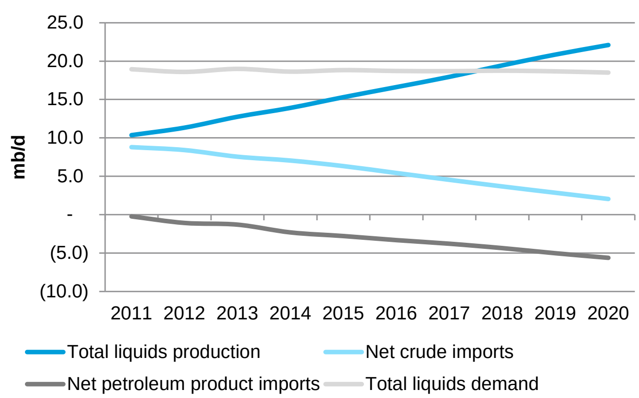
Even as crude oil exports grow, refinery capacity expansions (and even new greenfield projects, albeit small ones) have been planned to run more of the abundant local light sweet crude supply in the US. With advantaged crude feedstock, plus access to cheap shale gas, refineries can run at high utilization rates to serve the global market. With US petroleum demand declining – particularly in the road transportation sector – exports of petroleum products should continue to rise, as they have already. (An exception would be NGL exports, where homegrown petrochemicals facilities are being built rapidly to utilize cheap local feedstock.) Oil demand trends are discussed in a later section.

Figure 13. Citi's base case: US becomes net crude + product exporter in 2020



Source: EIA, Citi Research

Figure 14. Citi's high case: US becomes net crude + product exporter by 2018



Source: EIA, Citi Research

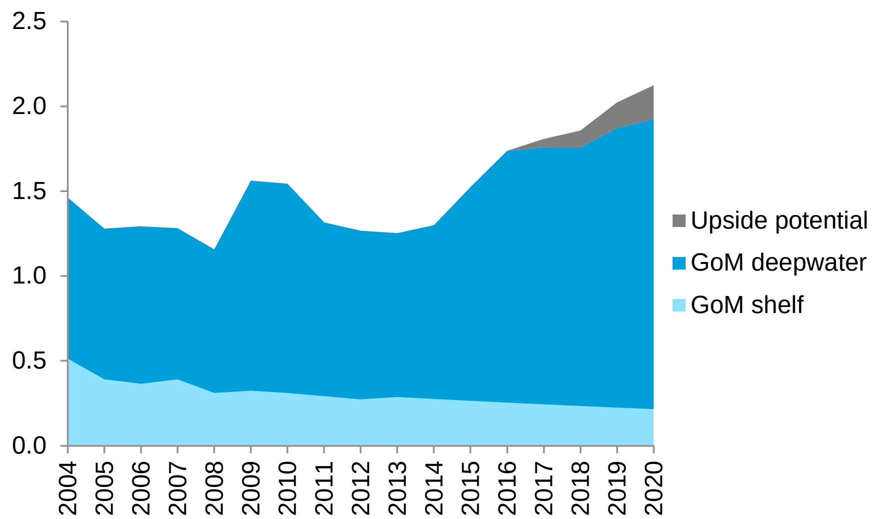
Citi projects net petroleum product exports (including NGLs from field production) to rise from 2.3-m b/d in 2014 to 4.7-m b/d by 2020 in the base case, and as high as 5.6-m b/d by 2020 in the high case. Both cases extend the recent historical trend, with net petroleum *imports* at its peak of 13.4-m b/d for the month of August in 2006 now looking to flip dramatically to massive net petroleum exports.

The section below goes further into the outlook for onshore and offshore crude production and examines the following impacts: (1) how this drives crude exports over time; (2) refined petroleum product exports; (3) falling crude imports from major oil producer countries; and (4) a spotlight on condensate production and exports.

US offshore oil production growth

US offshore production is primarily from the Gulf of Mexico, and grew from just under 1.2-m b/d in 2008 to over 1.5-m b/d in 2009-10 before the Deepwater Horizon/ Macondo disaster caused a drilling moratorium and reassessment of safety standards and regulations. The earlier spurt in production growth came with the start-up of large fields like Atlantis, Shenzi, Tahiti, Thunder Horse and others. In the wake of the lifting of the post-Macondo moratorium on deepwater permitting and drilling, activity has been picking up again. Exploratory permitting activity returned to pre-Macondo levels in 2012, and 10 new discoveries were made in 2013, with notable ones including Gila, Coronado, and Yucatan; the pace of discoveries has slowed in 2014, but this is also as the focus has moved to developing existing areas as legacy fields decline.

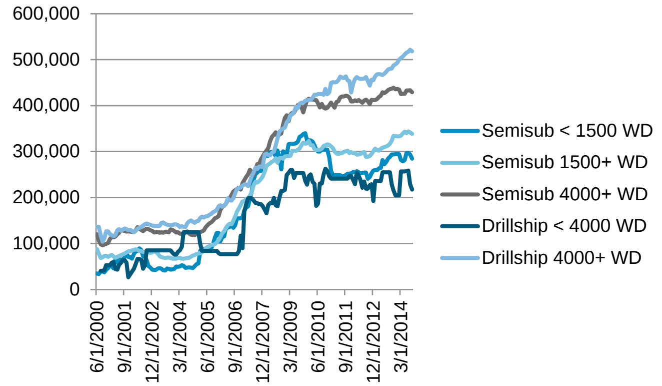
Figure 15. Gulf of Mexico crude production outlook (m b/d, 2004-2020E)



Source: Wood Mackenzie, Citi Research

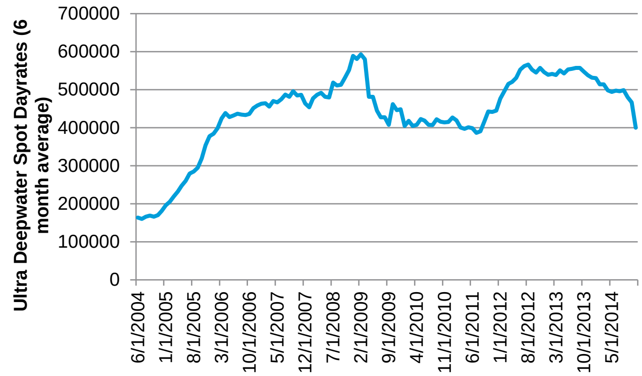
Offshore oil production now looks to rise from 1.3-m b/d currently, to ~2-m b/d before 2020. At mid-2014, there are estimated remaining offshore commercial reserves of 12-bn bbls of oil and 10.1-Tcf of natural gas. New fields driving production growth include Big Foot, Hadrian, Heidelberg, Lucius, Jack, St Malo, Stampede, Tiber, Vito. Closer to 2020, new discoveries can add additional volumes, with upside potential.

Figure 16. Floating rig day rates for drillships and semisubmersibles ($/day, 2000-2014)



Source: Rigzone, Citi Research

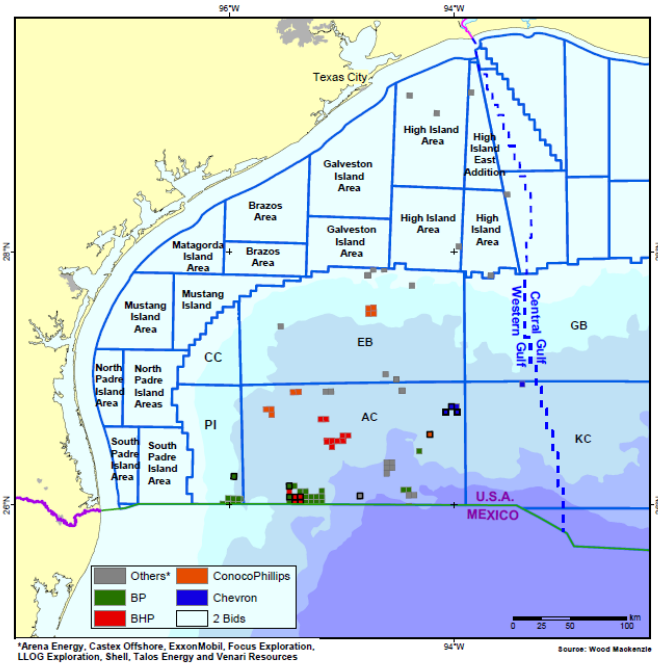
Figure 17. Ultra deepwater dayrates have started to decline recently



Source: Company reports, Citi Research

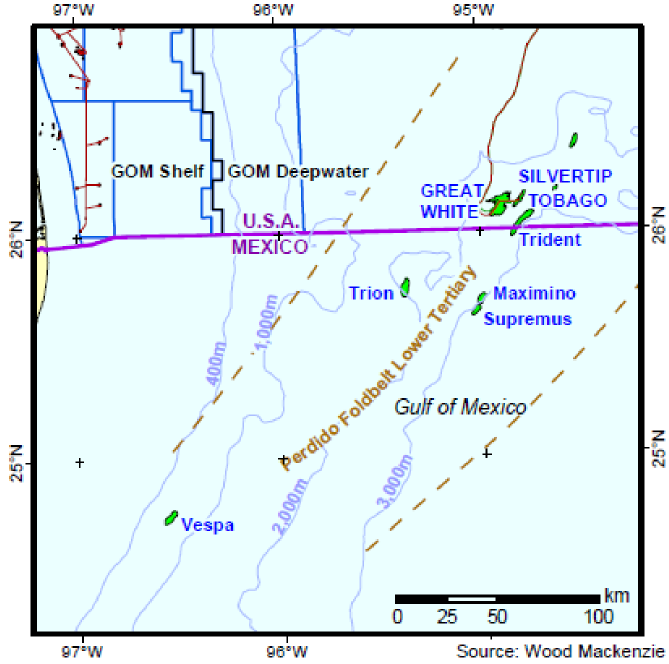
Reform developments in Mexico have boosted the outlook for offshore production in the Gulf of Mexico which has led to robust lease sales on the US side of the maritime border in the Gulf of Mexico. The energy reforms taking place in the US's southern neighbor have awakened interest in the Mexican upstream, previously closed to overseas players. (Midstream and downstream opportunities abound too.) The Mexican upstream presents opportunities in four major areas in particular: onshore conventional, onshore unconventional (shale), offshore shallow water, and offshore deepwater. Pemex, Mexico's state-owned petroleum company has had some recent success with three deepwater projects in the Perdido Fold Belt, and the energy reforms allow partnering with international players to develop this further. But this has also driven a resurgence in interest in lease sales on the abutting US side of the Gulf of Mexico. 33 out of the 73 deepwater high bids of the recent Western Lease Sale 238 (WLS 238) – some $35.7 million's worth – were focused on these US-Mexico maritime border areas; ExxonMobil, BP, Shell, and BHP were among the most active players.

Figure 18. Many of the deepwater bids for WLS 238 were on the US-Mexico maritime border, driven by renewed interest on the adjacent Perdido Fold Belt plays following the Mexican energy reforms



Source: Wood Mackenzie

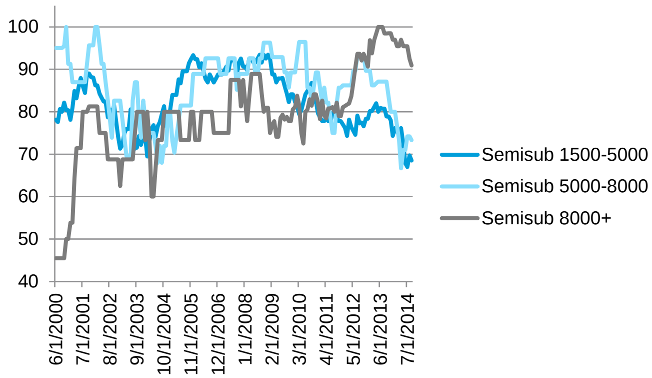
Figure 19. Mexican Gulf of Mexico Perdido Fold Belt could see further development from partnerships between Pemex and international players



Source: Wood Mackenzie

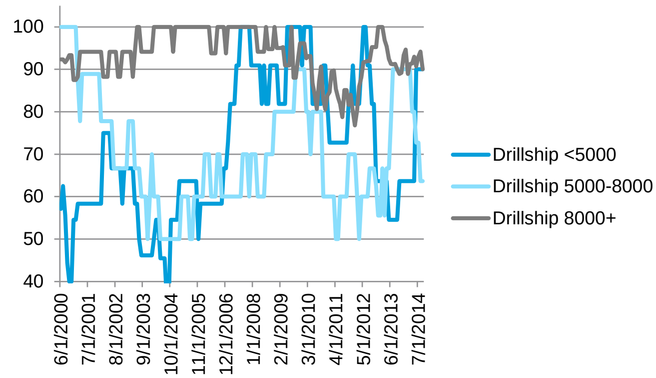
The deepwater services sector saw rising costs after 2005 as demand for rigs and drill ships overheated the sector. These costs have since plateaued from 2009 onwards, although there has been an increase in day rates after 2013-14 for rigs capable of working in particularly deep waters. These costs bear watching and can slow deepwater production growth if they get too high, but can fall as the backlog of new rigs comes online. Indeed, spot market rates for ultra-deep water rigs have now fallen by more than a third since the high plateau levels shown in Figure 17, but realized rates have yet to show this deflationary trend, due to the fact that contracts are of long duration. As contracts come around, these costs are expected to fall and are significant components in deepwater projects – rig rates can drive about half the cost of an exploration well, and a quarter of the project cost of a development program. The opening of Mexican deepwater resources could put another bid into the services sector in the latter half of this decade, but it looks as though deepwater project costs can continue to ease over time.

Figure 20. Utilization rates of floating rigs (semisubmersibles, %)



Source: Rigzone, Citi Research

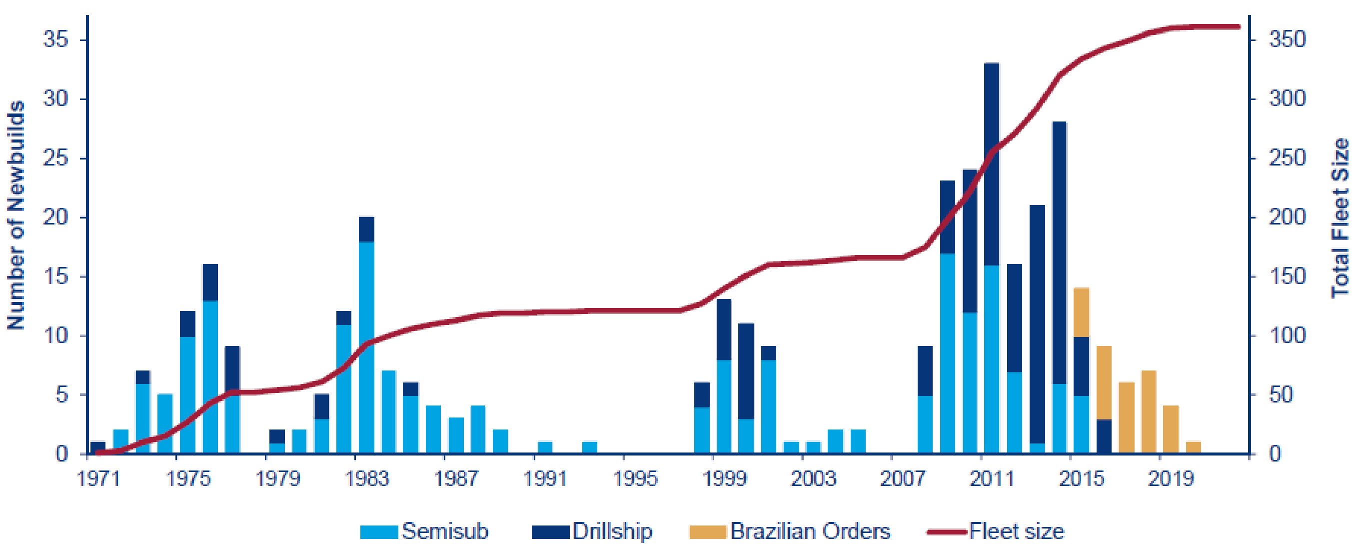
Figure 21. Utilization rates of floating rigs (drillships, %)



Source: Rigzone, Citi Research

In both the base and high case outlook for US oil production, US Gulf of Mexico production is projected to rise to potentially over 2-m b/d. Yet there are scenarios in which offshore production could rise even more**, given the lifting of the moratorium and the opening of Mexico's deepwater to private exploration and the recent heightened interest in the US deepwater areas adjacent to Mexico's territorial waters.**

Figure 22. Deepwater rig fleet by rig type, delivery year



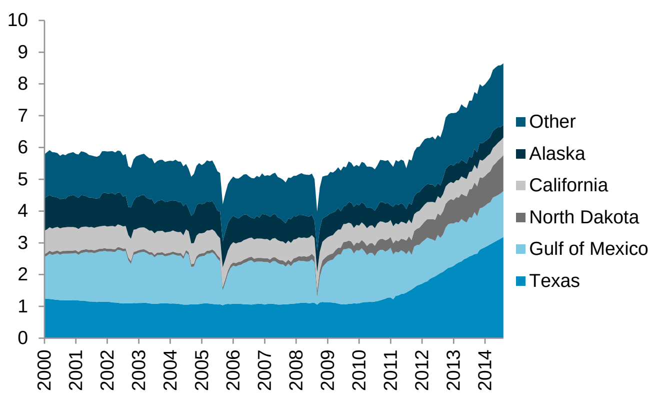
Source: Wood Mackenzie

US onshore crude production growth

Oil production from shale plays in the US has already grown from zero to over 4.5-m b/d currently, and looks likely to rise to 7.6-m b/d by 2020 in our base scenario, and as high as 9.2-m b/d in our more optimistic scenario, which involves a combination of improved efficiencies and a lifting of export constraints. For our purposes, our base case is supported by a deceleration toward lower growth in production than has been the case over the past three years, while our more robust supply outlook sees broadly a continuation of the same level of volumetric production growth that has been in place over the past three years.

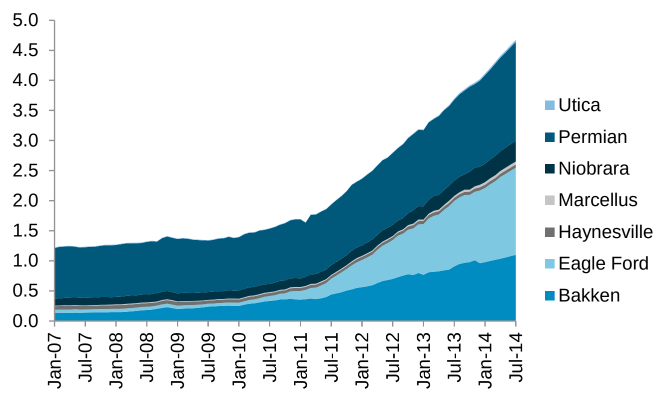
Combined with deepwater medium sour crude production in the Gulf of Mexico, US crude oil production could rise from ~8.5-m b/d currently to 12.5-m b/d by 2020 in our base case. Our more robust case projects crude oil output to grow to 14.2-m b/d by 2020. Oil production has been driven by the Big Three shale plays of the Bakken in North Dakota and eastern Montana, the Eagle Ford in southwest Texas, and the Permian Basin in west Texas and southeast New Mexico, with many small but significant contributions from smaller plays — including the much-touted Oklahoma plays in the Anadarko Basin and SCOOP area (the South-Central Oklahoma Oil Province), touted as the new Bakken. Shale formations know no country borders, of course; the Bakken also extends into shale plays in western Canada, while the Eagle Ford extends into Mexico's Burgos Basin. The three big plays continue to drive shale/tight oil production growth going forward, helped by contributions from smaller and emerging plays like the Niobrara, and others in the Rockies and midcontinent regions. (We have not factored in any contributions from any potential plays in California where complex geology has met complex politics putting a damper on exploitation any time soon. See "Much Ado About Nothing?", 28 May 2014, Eric G. Lee et al.)

Figure 23. US crude production by state/region (m b/d, 2000-14)



Source: EIA, Citi Research

Figure 24. US shale liquids production by major play (m b/d, 2007-14)

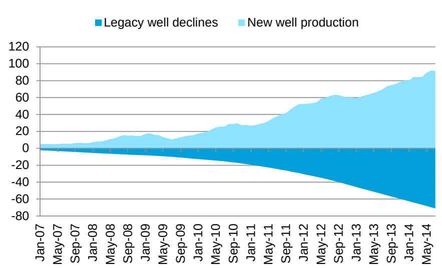


Source: EIA, Citi Research

Drilling activity has risen and stays strong

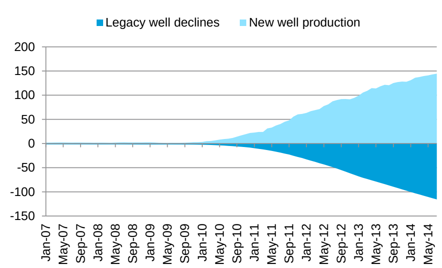
The number of horizontal rigs (employed alongside hydraulic fracturing to access shale production) in the US has risen from ~150 in 2005 up to 1,200 by mid-2012, where it hovered at ~1,250 for a while, and then continued to rise in recent months. Meanwhile, production efficiency gains have been substantial, as mentioned earlier.

Figure 25. Bakken new-well production versus legacy well declines (k b/d, 2007-14)



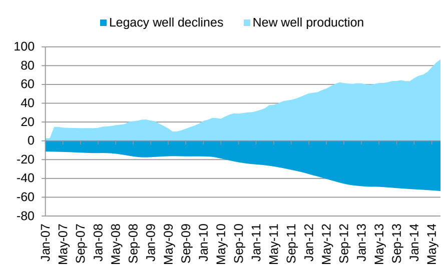
Source: EIA, Citi Research

Figure 26. Eagle Ford new-well production versus legacy well declines (k b/d, 2007-14)



Source: EIA, Citi Research

Figure 27. Permian Basin new-well production versus legacy well declines (k b/d, 2007-14)



Source: EIA, Citi Research

Shale production exhibits sharp initial declines, but…

Shale drilling has a different production and investment profile to conventional oil production. Single wells have a different "type curve", exhibiting fast declines in the first year, meaning on the one hand that cost recovery is quick, but on the other hand that as more wells are drilled in a shale play, the aggregate decline of the shale play as a whole increases. Put another way, more wells must be drilled for the same absolute level of production growth in the play, unless offset by more rigs or higher productivity gains. This tends to mean that production growth should at some point decelerate, with efficiency gains allowing access to higher plateaus of oil production. The US Energy Information Administration's (EIA's) drilling and productivity report shows the agency's analysis of this issue – for example, the Bakken shows legacy wells declining at ~70-k b/d for the month of July 2014, with new-well production rising to +90-k b/d and giving a net monthly gain of +20-k b/d. This rising new-well production per rig number reflects productivity growth, with ongoing improvements driven by the widespread transition to multi-well pad drilling, which reduces costs and saves time, as well as optimizing completion and well design, and other efficiency gains.

…these play-level declines flatten out over time as more wells move from the fast decline phase to the long tail phase …

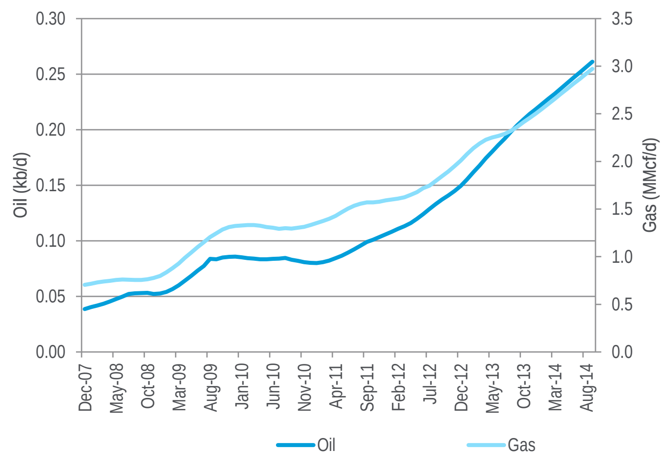
At the early stage of a shale play, most of the wells are new and are in their fast growth, fast decline phase. A constant rate of drilling without productivity gains yields an aggregate production growth rate that is decelerating. The total decline of all legacy wells is increasing. **But at later stages of a shale play, many of these past wells have moved to the long tail, characterized by a slow decline. Here, the total decline of all legacy wells could actually decrease and stabilize.** This means that there could be a long plateau for shale plays, rather than the sharp decline that has often been prognosticated – and this is not taking into account productivity gains, working over wells, or targeting of lower benches. In particular, oil wells could actually have lower decline rates than gas wells in the later stages of their lifecycle, given lower permeability (or a lower final b-factor, in terms of a type curve model). This could mean even flatter tails, although at some point years down the line, the wells could see economic shut-ins. This is not considering further potential workovers of wells which could add another bump up in production. And, to be sure, the still-limited historical series for data may not yet give a full picture of the longer-term performance of shale/ tight oil wells. For instance, the long-run natural gas cut of wells may be higher too over time.

…and productivity gains continue apace, improving production, and recovery and lowering costs

As has become clearer over time, exploitation of unconventional resources in the United States and to some extent in Canada cannot be understood in terms of a traditional "exploration and production" framework, which is built around conventional resources that are "trapped" within fairly open reservoirs that, once discovered, release large volumes of oil or gas (or both in association). The process of exploitation of shale and tight formations is both more seamless than in the case of traditional E&P and is prone toward capturing lower costs for a more prolonged period of time than with earlier technologies working in more mature areas of exploitation.

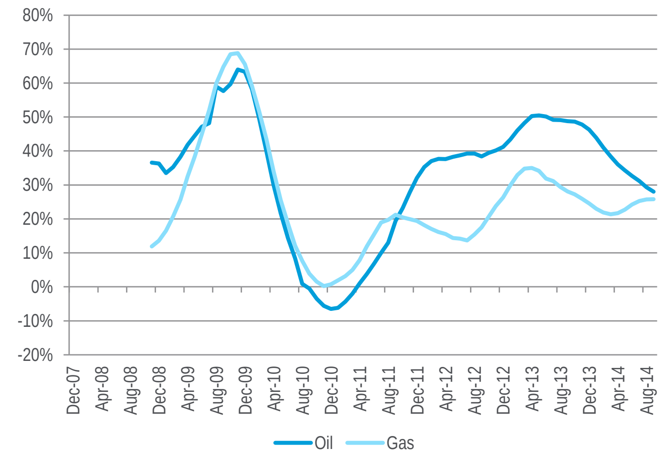
Traditionally for conventional development, exploration using risk capital is a phase designed to prove up discoveries and move them toward a distinct phase of development, which triggers a release of hydrocarbons over a long period of time. Enhanced recovery procedures can be developed and project economics for their use are akin to project economics post-discovery and proving up reserves for development. **In comparison, in tight oil and shale gas development** once a resource base is understood, project economics are essentially development economics and while this involves a significantly higher cost structure for operations, it is a cost structure that is prone toward secular improvements and efficiency gains, all else equal. It's also a cost structure that depends on service costs, which are high when the balance of supply and demand for services is tight, but is also prone to move toward lower costs as competition in the services sector is raised over time.

Figure 28. First month national oil/liquids and gas production per rig, weighted-average of the seven plays (2007-2014)



Source: EIA, Citi Research

Figure 29. Productivity gains (y/y change in production per rig; weighted-average of the seven plays)



Source: EIA, Citi Research

Based on the latest data collected and analyzed by the EIA, the average first month oil/liquids and gas production per rig has increased sharply. Since 2012, overall productivity gains (year-on-year change in production per rig) have hovered around 30% to 40% for oil/liquids plays and the low-10% for gas plays. There is no sign of any sharp deceleration in productivity gains yet. However, improvements are differentiated across plays, possibly underscoring the maturity of some plays and the changing focus of production. (See the "US Oil and Gas Drilling Productivity Report" for details at the play level, and an update in "Drill, baby, drill?", Aug, 2014)

Technology and terminology of shale hydrocarbon production

Technological improvements and learning-by-doing have been key to strong productivity gains.

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

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

- Better well-bore placement and fracturing design have helped to keep gas production high despite low rig counts.
- Reduced cluster spacing, by shortening the spacing between fracturing stages leading to more perforations in the lateral of the wellbore, should boost production by creating more fractures.
- Geo-steering allows the wellbore to better fit the shale layer, increasing the exposure of the wellbore to more oil/gas.
- Increases in computing power, particularly for detailed 3-D geological modelling and analysis, have made simulation more effective.
- Proppants are critical in keeping fractures open, among other uses. An increased understanding on the use of proppants could boost recovery rates of oil and gas, with the use of different mixes of proppants.

Finally, the economics of production can mean that companies at times prioritize raising production levels, at other times prioritize cost control while keeping production constant, and at other times introduce new technology at higher prices to boost production and recovery rates. Infrastructure and policy bottlenecks can depress local prices to ration supply, which also create wide-enough price differentials between production areas and demand areas to encourage new transportation infrastructure investment.

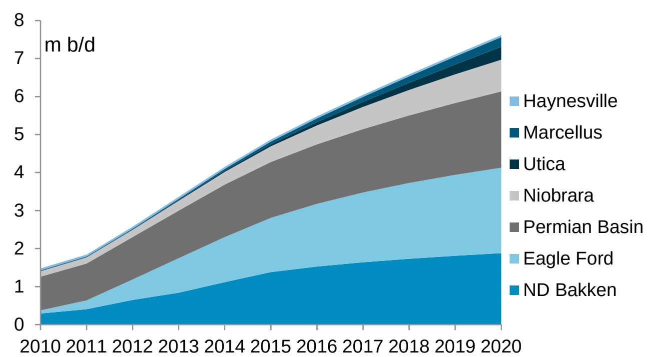
Marginal production economics, which drive drilling behavior in existing plays, look quite competitive versus prevailing oil prices. Hence, if the "marginal cost" for existing producers is the cost of drilling the next well in an existing field, then it would consist of lease operating expenses, such as operating cost, royalties and gathering cost, and the cost of drilling/completion/fracturing. Land acquisition, exploration and other additional overhead costs could be considered sunk already. In this context, the "marginal cost" of drilling the next Bakken or Eagle Ford oil well may be in the low-$40/bbl range or below. This compares favorably with current oil prices.

The productivity of a well is also measured using other key metrics, such as Initial Production (IP) and Estimated Ultimate Recovery (EUR). IP typically refers to the average production in the first 30 days. The magnitude of the production generally signals how large (or how much oil/gas) a well could be. EUR is an estimate of how much oil or gas could be produced over the entire lifespan of a well, subject to an economic limit. An economic limit is hit when the revenue from oil or gas produced does not cover the operation cost of a well.

Limits and risks to shale production growth

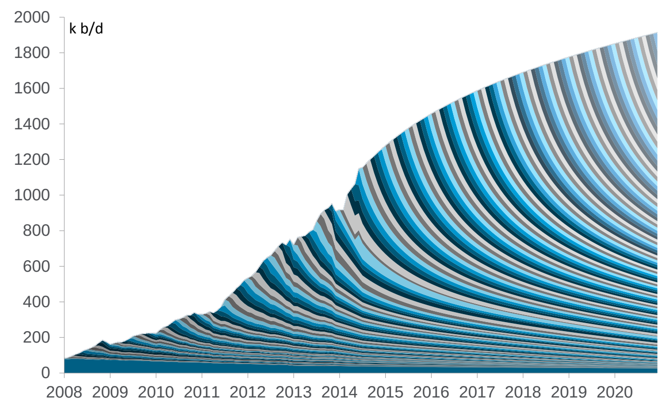
Working against productivity gains is the move away from geological sweet spots, and deterioration of initial production rates (IPs) and estimated ultimate recovery quantities (EURs) as well down-spacing moves to a certain threshold. Thus, well locations are not infinite, and their performance, in terms of IPs, EURs, and type curve shape, could deteriorate over time. The total cumulative production of the play would be limited by how far recovery rates can be increased from the hydrocarbons in place, though given current recovery rates are at the mid-to-low single digit percentages, versus mid-double digit rates for conventional reservoirs, there appears to be substantial headroom to improve. In our base case projections, we assume productivity gains are zero in the forecasted period.

Figure 30. US shale liquids outlook, base case (m b/d, 2010-2020E)



Source: DrillingInfo, EIA, Citi Research

Figure 31. North Dakota production outlook (kb/d, 2008-2020E)

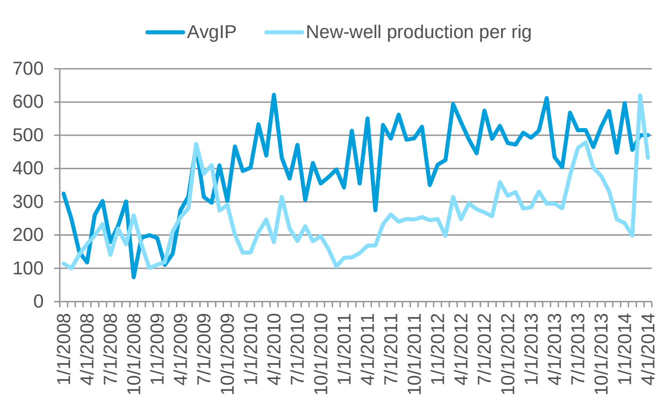


Source: DrillingInfo, Citi Research

Shale oil production outlook, play by play

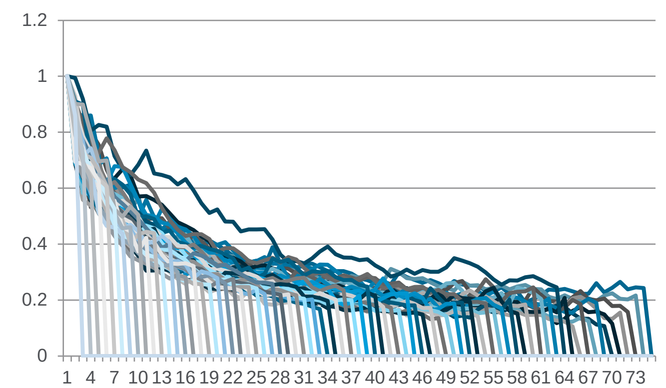
Bakken production, already over 1.1-m b/d, is driven mainly by McKenzie, Mountrail, Williams, and Dunn counties, and although average first-full-month IP rates seem to have stabilized at around 450-600 b/d per well, the best-performing wells still seem to be seeing higher and higher IPs; this is as over ~200 wells are drilled and completed per month by ~190 rigs. North Dakota already saw production reach 1.1-m b/d by mid-2014, and could achieve ~250- to 300-k b/d of y/y growth in 2014. Despite a possible deceleration in growth going forward and net new-well production per rig remaining flat, **total production could still grow 1.3-m b/d to 2.4-m b/d over 2014-2020.**

Figure 32. Bakken IPs and new-well production per rig (b/d)



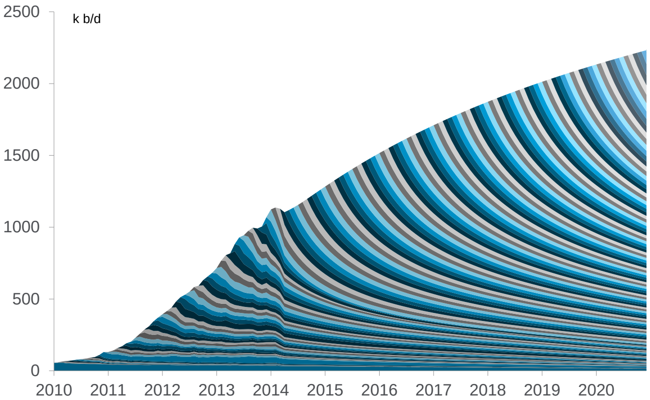
Source: DrillingInfo, Citi Research

Figure 33. Bakken oil/liquids production trajectory by vintage month, normalized (indexed to first full month's production)



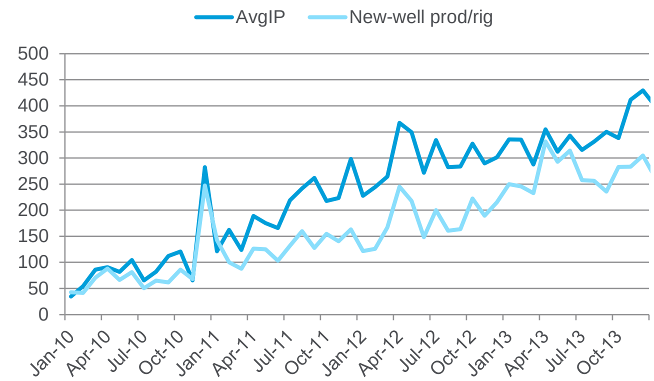
Source: DrillingInfo, Citi Research

Figure 34. Eagle Ford oil/liquids production outlook (k b/d, 2010-2020E)



Source: DrillingInfo, Citi Research

Figure 35. Eagle Ford IPs and new-well production per rig (b/d)

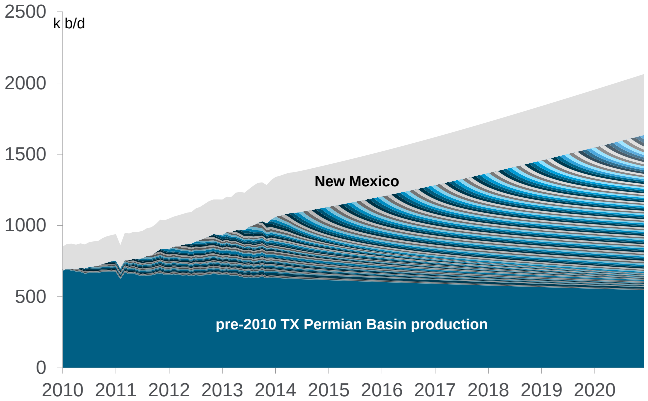


Source: DrillingInfo, Citi Research

The **Eagle Ford**, **producing around 1.4-m b/d in mid-2014**, sees the lion's share of production from Karnes, LaSalle, DeWitt, Gonzales, Dimmit, McMullen and Webb counties, and here IP rates have been rising steadily from 200-300 b/d in 2012 to 350-400 b/d. Some 200-250 wells are being drilled per month by ~210 rigs. The play can continue to grow by ~250- to 300-k b/d annually or more, and given productivity gains seem to be going strong, should continue to perform; infrastructure takeaway and pricing for condensate-rich Eagle Ford production could hit realized prices though, but Citi's optimistic outlook on US crude export policy loosening would imply that this headwind could be eased over time; however, the broader global looseness in condensate and naphtha markets could yet have a boomerang effect further down the line. With net new-well production per rig flat**, the Eagle Ford could grow 1.7-m b/d over 2014-2020 to reach 2.9-m b/d.**

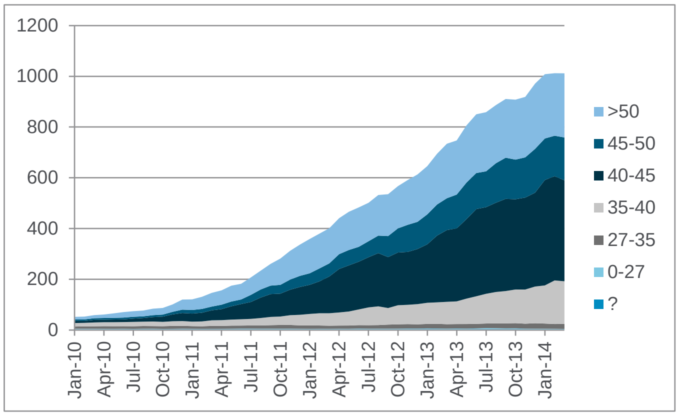
The **Permian Basin, producing around ~1.5-m b/d in mid-2014**, is made up of two main areas – the Midland Basin is driven by counties like Irion, Reagan, Andrews, Crockett and others; and the Delaware Basin, driven by counties in Texas and New Mexico like Eddy, Lea, Ward, Loving, Reeves and others. Average first-full-month IP rates are still rising, from 50 b/d levels in 2011 to 70 b/d levels in 2012 and 90 b/d levels in 2013, and still look to be climbing to 100 b/d and up, driven by wider adoption of horizontal drilling which can take IPs toward the 500 b/d level and up, helping new-well production far outpace legacy declines, which have plateaued somewhat for now. Over 200 wells were drilled per month around the first quarter of 2014 and this pace can increase, with the play growing by over 100-200-k b/d per year. Legacy declines in particular look to have stabilized as previous vintage month wells have seen slow declines from the second year onwards, while new-well production has continued to grow; this could mean the production growth accelerates in the near-term. With new-well production per rig staying flat, **Permian Basin production could grow by at least 1-m b/d to 2.3-m b/d over 2014-2020.**

Figure 36. Permian Basin oil/liquids production outlook (legacy, Texas and New Mexico, k b/d, 2010-2020E)



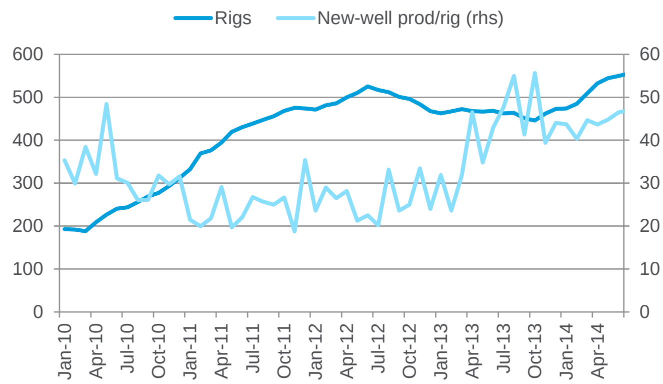
Source: DrillingInfo, Citi Research

Figure 37. Eagle Ford liquids production by API gravity



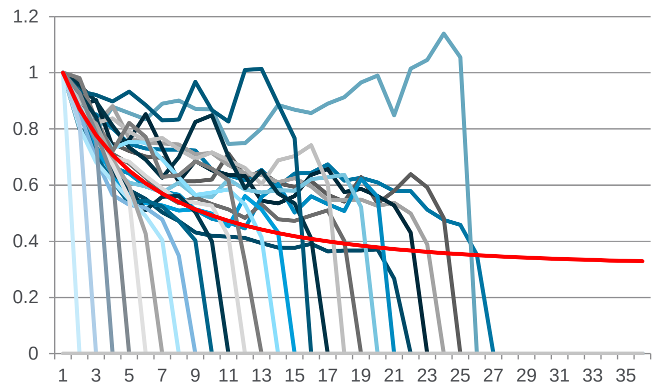
Source: DrillingInfo, Citi Research

Figure 38. Permian Basin IPs and new-well production per rig (b/d)



Source: DrillingInfo, Citi Research

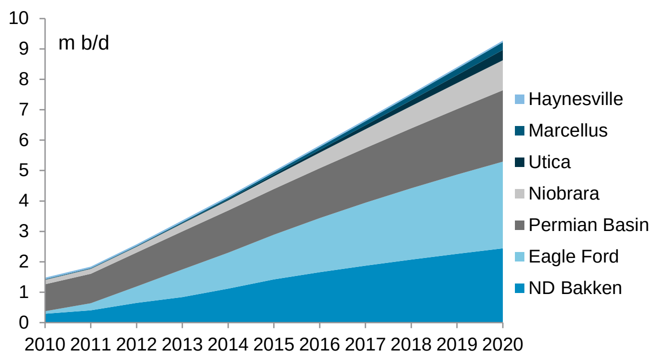
Figure 39. Permian Basin oil/liquids production by selected vintage month – note the flatter declines and later workovers that could provide upside (b/d)



Source: DrillingInfo, Citi Research

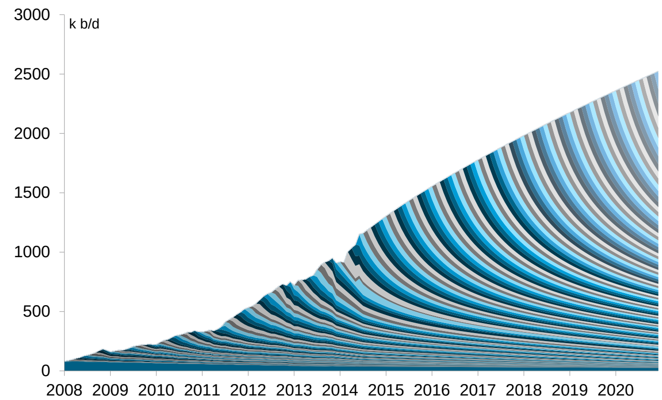
Other emerging liquids plays are also adding to production volumes, though there are not yet any that are of the size of the "Big Three". The Niobrara has raised its production profile to over 300-k b/d, and while flooding has affected production at times, continued learning-by-doing and longer well laterals should continue to boost productivity here, with most of the activity since 2011 taking place in Weld, CO and Laramie, WY counties in the Denver-Jules Basin Niobrara, and Converse and Campbell counties in Wyoming in the Powder River Basin Niobrara area. Much of Niobrara production is 50+ API gravity condensate. Meanwhile, other plays in Oklahoma, Texas and Louisiana can add further volumes. Oklahoma in particular has been touted as a place where resources have been exploited for a long time and where current output of some 300-k b/d could grow significantly. Already Oklahoma production is up more than 50% from 209-k b/d in 2011 to 312-k b/d at end 2013 and 360-k b/d in 2Q'14. Consultants Wood Mackenzie indicate that increases in production in the SCOOP (South Central Oklahoma Oil Province) and other basins in Oklahoma could boost total state production back to its earlier peak of 760-k b/d by 2020.

Figure 40. US shale liquids outlook, high case (m b/d, 2010-2020E)



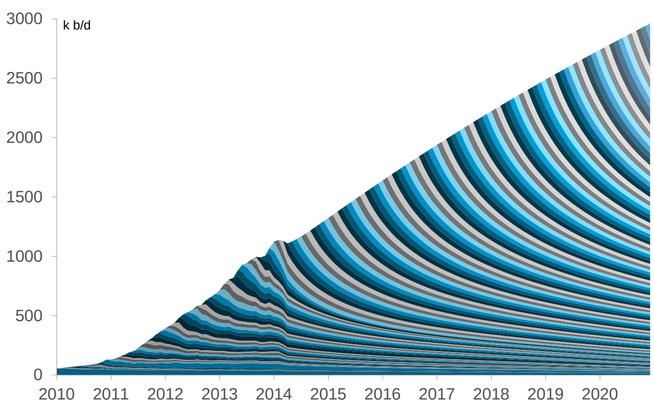
Source: EIA, Citi Research

Figure 41. North Dakota production outlook, high case (m b/d, 2010-2020E)



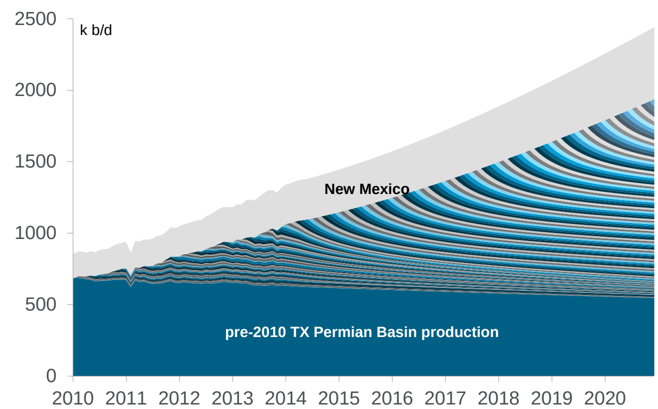
Source: DrillingInfo, Citi Research

Figure 42. Eagle Ford production outlook, high case (m b/d, 2010-2020E)



Source: DrillingInfo, Citi Research

Figure 43. Permian Basin production outlook, high case (m b/d, 2010-2020E)



Source: DrillingInfo, Citi Research

In the high case, each of these main plays could see growth rates continue at current levels for longer, without decelerating, as ongoing high and stable rig counts work through a robust inventory of well locations this decade. With ongoing modest productivity gains outweighing productivity losses, such that on net, new-well production per rig rises by 10% annually at first and then slopes off**, the Bakken could reach 2.5-m b/d by the end of the decade, the Eagle Ford could reach almost 3-m b/d, and the Permian Basin almost 2.5-m b/d and** total (tracked) shale liquids production could rise 5-m b/d over 2014-2020.

Six big issues beyond efficiency gains raise misleading questions about sustainability/profitability of shale exploitation

Despite the extraordinary growth of shale gas and tight oil production in the United States, there remain underlying doubts in a number of quarters about the sustainability and profitability of exploiting unconventional resources. Six issues in particular are favorites not only of those analysts, investors and market participants who remain wedded to peak oil theory, but to others who recognize the surprising nature of recent production gains in the US but believe there is evidence that these gains might be ephemeral. Citi believes that these concerns are not serious impediments to the continued unfolding of the shale revolution. Here is a list of these six big issues:

1. **The persistent negative cash flow of the industry will never end.** As the shale gas supply explosion tapered after 2011 and oil directional drilling took off, the US oil and gas industry moved from being cash flow positive in 2009 (by some $22.8 billion according to IHS), to being increasingly cash flow negative (by $40.9 billion in 2011, and a giant $58.1 billion in 2012). Cash flow improved significantly after that, even as capital expenditure (capex) also continued to grow, with IHS reporting a more modest negative cash flow of $31.1 billion in 2013. This past August, the *Financial Times* commissioned a survey of equity analysts of the 25 leading North American producers, concluding that by 2015 these firms would become cash flow positive and in the years thereafter. That should not be surprising. Before 2012 much of upstream capex was on acreage acquisition. There was a massive land grab to tie up promising acreage. In addition to high and rising acreage acquisition costs, work requirements were fulfilled at minimum levels as the land grab continued and as minimum spending was needed to hold acreage and meet minimal obligations. This process masked underlying efficiency gains described in this report and understated the pace of technological innovation. On the natural gas side, lower than expected prices reduced cash flows against expectations and often firms turned to oil directional drilling. Only starting in 2013 was a more mature phase of development entered with cash flows in some plays starting to exceed capex. Companies with extensive resource bases should see solid cash flow growth, with output increases potentially accelerating.

2. **Asset write-downs have been exorbitant with large firms exiting shale plays.** There is little doubt about this phenomenon, but it also should not be surprising. The land grab took place in a high natural gas price environment, and the booking of reserves took place in an overly optimistic price environment. Year-end reserves reported by firms grew from 2008. Just as activities moved from gas- to oil-directional drilling and natural gas prices fell to the low $2 range, companies that had booked reserves at a higher price level had to write them off. Some companies actually exited both unconventional oil and gas plays. But lower prices do not mean that the reserves are not there or available for development. Indeed as companies move into a more positive cash flow environment, production should be sustainable at lower oil price levels.

3. **Decline rates remain high and point to a significant decline in production if drilling falls off.** Again this reflects a fundamental misunderstanding about the nature of shale exploitation. As we have explained in the analysis of productivity gains, it is now clear that a tipping point to accelerated declines is nowhere in sight. Plateau levels can be maintained for very long periods of time and the resource base for both natural gas and oil is both incredibly extensive and significantly higher recoverability is in store, well above today's technical limits of ~5%. The most worrisome factor would be the potential impact on drilling of a price collapse, and in that sense OPEC's desire to maintain a floor under prices serves as a strong "subsidy" to shale drilling.

4. **Environmental issues remain open and could force a significant curtailment in drilling.** This is in fact a potentially serious issue. While it is clear that best practices can effectively balance concerns about water use, aquifer integrity, above ground waste disposal and fracking-induced seismic activity, there are problems related to the adoption of best practices in the US on a state level as well as globally as fracking spreads around the world. In addition monitoring industry practices is also difficult in that it is human-resource intensive and costly.

5. **Is the shale revolution replicable outside the US?** The unique combination of factors that has enabled the shale revolution to emerge in the United States are well known, including well understood geology, the availability of a highly developed services sector, an established transportation system, the existence of highly entrepreneurial independent companies, a financial services sector willing to provide risk capital to cash-poor independents, and the private ownership of mineral property rights, giving land-owners a massive incentive to participate in exploitation. To be sure

these are big obstacles for other hopeful producing nations, but where there is a will there is a way. Already there is about 700-k b/d of shale oil produced outside the US (in Canada, Russia, Argentina and elsewhere) and it looks as though this level could well triple by 2020, including new developments in Mexico and Australia.

6. **Will lower oil prices spoil the party?** Undoubtedly the shale revolution started in a significantly higher priced environment than currently prevails in natural gas. However, the cost curves for both oil and natural gas in the United States are coming down. Prices need to be higher for unconventional oil and gas exploitation than for traditional oil exploitation, but as relatively cheap oil has become more constrained and out of reach for both economic and political reasons, and as oil producing countries have developed a need for higher oil prices to balance their budgets, there is a certain level of production for unconventional plays. What's more, as has been clear in the US natural gas patch, lower prices make certain plays less competitive than they previously were, but this doesn't mean that drilling stops or overall production declines. At worst, it is now clearly the case that lower prices could curtail oil drilling, impact production growth and maybe over time production. But the impact on production could be thought of as "temporary" and limited in that the drilling and production response would be expected to be significant as technology improves and prices eventually rise.

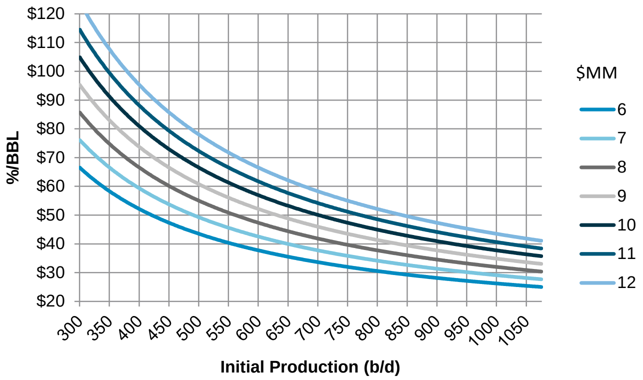
How low can shale production go?

Over the third and fourth quarters of 2014, oil prices capitulated, leading some to expect OPEC producers to cut output to support prices. But indications have emerged that suggest Saudi Arabia could look to allow prices to fall enough until US shale production is reined in.

However, should such a circumstance arise, it looks like US shale/tight oil production growth could remain robust even in an environment of sustained lower oil prices, lower capex, and lower rig counts. This is discussed in the Citi Research report "The Abyss Stares Back: In a stand-off between OPEC and US shale, how low can shale go?"

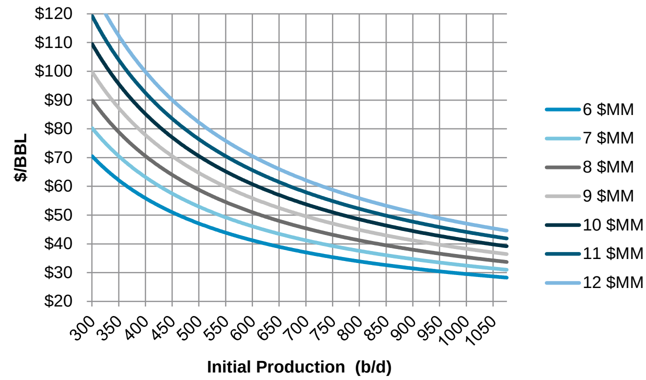
At what price might US shale production growth be meaningfully reined in? Full-cycle capex for shale production includes land, infrastructure, and well costs (of which some 40-50% is from pumps, ~10-15% for drilling rigs) and operating costs. In mature plays where the land grab is over and infrastructure is available, the remaining capex required ("half-cycle costs") to bring on an additional well is far lower than areas requiring "full-cycle" costs. Full-cycle costs might be as high as $70-80/bbl WTI, but half-cycle costs could be as low as the high $30s-range. Thus, those fringe and emerging areas requiring full-cycle capex could now face a reassessment, while established areas should continue drilling and growing output.

Figure 44. Eagle Ford well breakeven prices ($/bbl, y-axis) for various IPs (b/d, x-axis), at various well costs ($MM)



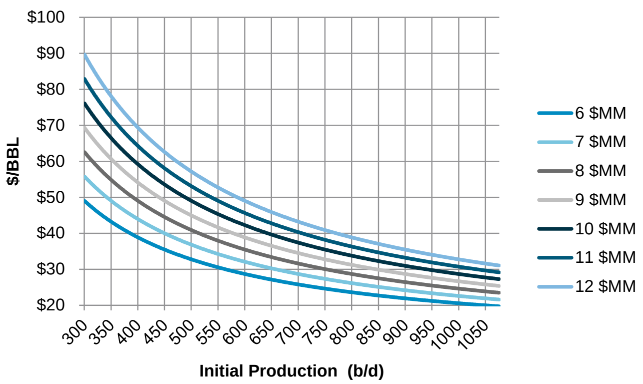
Source: Company reports, Citi Research

Figure 45. Permian Basin well breakeven prices ($/bbl, y-axis) for various IPs (b/d, x-axis), at various well costs ($MM)



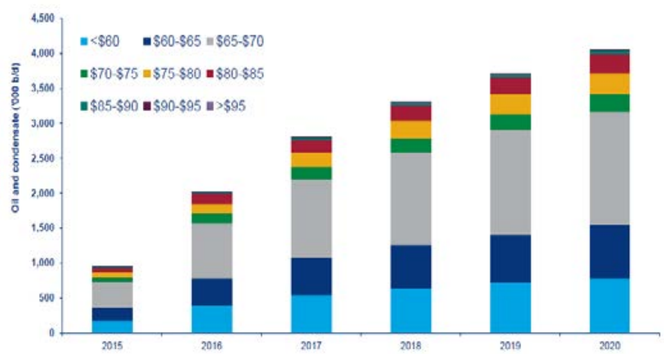
Source: Company reports, Citi Research

Figure 46. Bakken well breakeven prices ($/bbl, y-axis) for various IPs (b/d, x-axis), at various well costs ($MM)



Source: Company reports, Citi Research

Figure 47. Other estimates of Brent breakevens and reserve estimates for US tight oil sub-plays



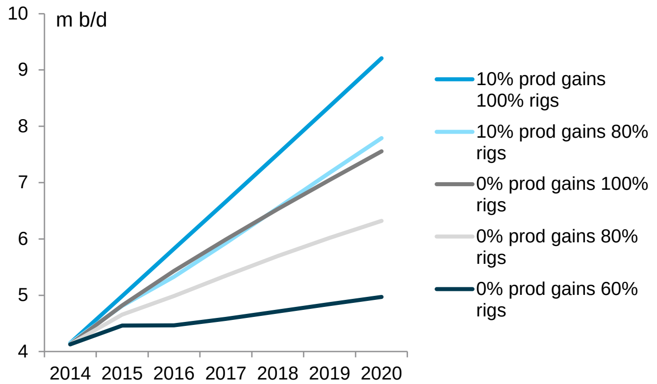
Source: Wood Mackenzie

Shale production breakeven prices are particularly driven by well productivity (i.e., initial production/IP) and well costs; there can be a wide range of IPs within a single play. Thus there is no single "cut off" price for share development. In the Eagle Ford, an $8 million well with IP of 400 b/d breaks even at ~$70 WTI, but an $8 million well with a 500 b/d IP breaks even at $55; fringe acreage should be the first to be cut. A $7 million well with a 400 b/d IP is economic at $60 WTI; well cost reductions matter too, and could fall by ~20% as services sector slack intensifies.

To triangulate how much US shale production growth might be curbed at $70 WTI, two approaches are considered: sensitivity to rig count reductions, and a look at the distribution of well IPs.

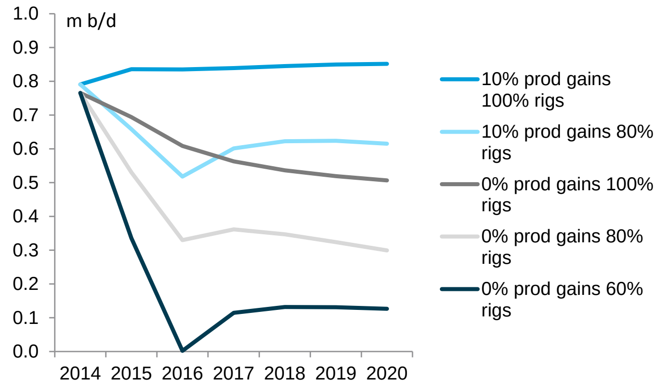
First, WTI prices below $70 could rein in as much as 25% of rigs; such a sustained rig reduction could lead to a ~25% fall in US shale output growth in 2015 and a ~50% fall in production growth in 2016. A 40% reduction in rigs or more might be needed to completely flatten production growth – but this is based on modeled reductions of average wells, not the least productive wells. Productivity gains can also offset this further. In any case, at $70 WTI, this is a slowdown, not a halt, in production growth.

Figure 48. US shale production outlook under rig count and productivity gain scenarios (m b/d)



Source: EIA, DrillingInfo, Citi Research

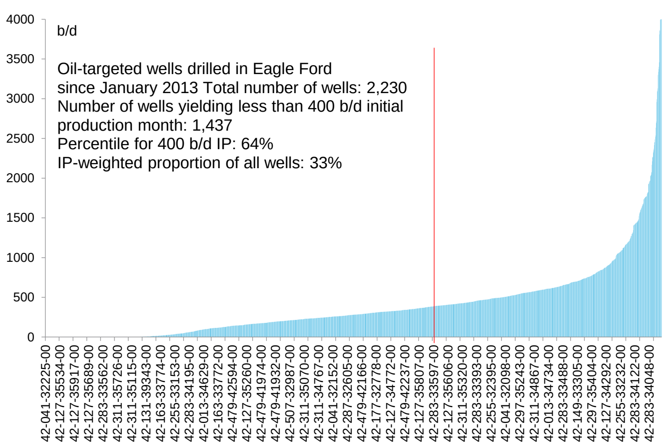
Figure 49. US shale production y/y growth under various rig count and productivity gain scenarios (m b/d)



Source: EIA, DrillingInfo, Citi Research

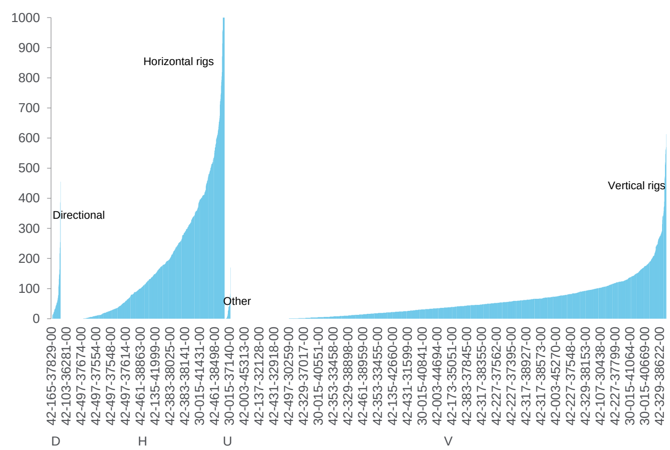
Second, an assessment of wells that might be left undrilled at $70 WTI can be made by looking at wells below certain IP rates (though well costs are not necessarily independent from IPs). A look at recent wells drilled suggests that even if ~70% of wells could become uneconomic at $70 WTI, they might only account for 30% of business-as-usual production. To take out enough new production to flatten production growth might require prices in the $50 range in the short-term.

Figure 50. Eagle Ford – IP (b/d) of oil wells drilled 1Q'13-1Q'14 (listed by API number)



Source: DrillingInfo, Citi Research

Figure 51. Permian Basin – IP (b/d) of oil wells drilled 1Q'13-1Q'14 (listed by API number), broken out by drill type – note that the growing number of horizontal wells drilled should boost IPs (noting that well costs should rise too)



Source: DrillingInfo, Citi Research

Additional factors create inertia that can slow producer pullbacks, such as sunk costs, well backlogs, and producer hedging.

1. **Sunk costs:** Some of these well costs are sunk – contracted pumps and rigs are sunk costs until the contracts run out. This could temporarily alter producer behavior, as producers ignore these sunk costs in production decisions, which as we have seen, can bring down the "effective breakeven" price further. Sunk well costs could be as high as 25%, which could lower the effective breakeven prices by over $10/bbl on a temporary basis until contracts end. Rig contracts tend to last around 18 months and will be slower to roll off. Pump contracts tend to be much shorter and thus less likely to be viewed as "sunk" if the time horizon under consideration is longer. As longer-term contracts are re-negotiated, they will be more fully reflected in breakeven economics.

2. **Focus on mature infrastructure plays:** If producers are incentivized to reduce capex, they will likely focus on plays that have significant infrastructure already developed.

3. **Well backlogs:** In fact, many areas, including the Eagle Ford and the Bakken, have significant well backlogs. This backlog reflects drilled-but-not-completed wells. A tighter focus on already drilled wells in areas with mature infrastructure could lower "average" breakeven costs across all plays (assuming similar geology in all locations).

4. **Hedging:** Hedging by oil producers means less sensitivity to prices in the near-term, which can keep drilling activity high and production growth strong. Citi's Commodities team's recent piece with the High Yield (HY) team, Peering Over the Oil Cliff, examines hedging programs for producers under Citi's HY coverage. Certainly, producers are hedged to various degrees and over time hedges roll off. Yet producers might also take advantage of any short-term price spikes from geopolitical disruptions – still very much a possibility given ongoing conflict in the Middle East – to hedge out forward production.

What's more, service sector costs should fall as rigs are idled. The response of the service sector to changes in total demand for drilling should create a boomerang effect. Some ~70% of well costs are due to several major components – pumps, rigs, and tubulars. As service sector utilization falls, so too should prices (and thus, margins) for services. Costs for inputs like drilling, pumps, and tubulars should drop, reducing required capex to drill new wells. This lowers breakeven costs, providing a mitigating force that lowers breakevens even as oil prices fall. Meanwhile, shale productivity gains can continue, reducing demand for rigs for a given level of wells drilled. WTI below $70 looks like it could bring down pump, rig, and tubular costs by some 25%, or equivalently, some ~20% (25% x 70%) of the total well cost, which could fall on a structural basis.

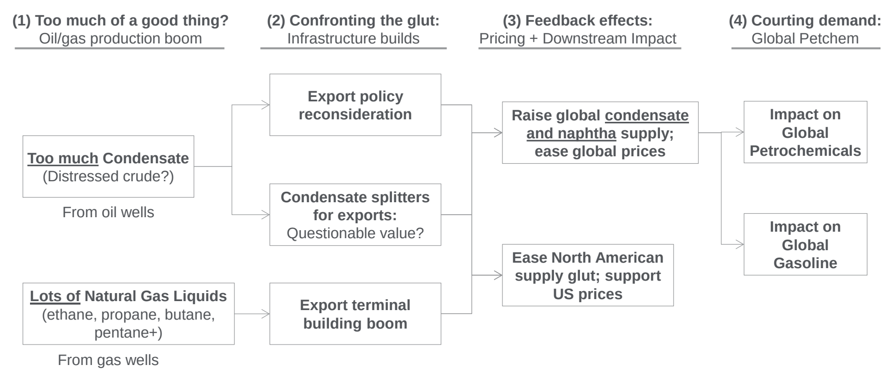
At the same time, prices for existing services and equipment are falling as new pump and rig supply backlogs are arriving on the market in 2015. A wave of new services equipment could put additional pressure on utilization rates and prices, further lowering break-even prices.

Condensate increasingly makes up a large part of crude production

An enormous political brouhaha emerged in June 2014 when it was learned that the US Commerce Department had clarified for two companies conditions in which field "condensates" could be stabilized and distilled and then allowed for exports. Condensates are light crude oil streams that are elaborated on below. The confusion about them stems from the fact that "plant condensates" processed in a refinery are classified as petroleum products and can be freely exported from the United States, while "lease condensates" produced in a field along with oil or natural gas cannot be. Lease condensates are classified as "crude oil" even though they are molecularly indistinguishable from plant condensates. The controversy stem from restrictions put in place in the price-controlled world of the 1970s and are regulatory legacies of change, but which put condensates in a politically difficult position in the domestic debate over whether oil should be exportable.

What are field condensates and NGLs? In the US, field or lease condensate (though it lacks an official definition) refers to very light oil, generally with API gravity at or above 50, that comes from oil-producing wells; NGLs, or natural gas liquids, which have a similar composition as field condensate but even lighter, are produced from natural gas wells, where the "wet" component is processed and "fractionated" to the constituent components, ordered from light to heavy: ethane, propane, butane and pentanes plus. Pentanes plus is often called "plant condensate" because of its similarity to "field condensate" from oil wells. The word "plant" refers to how pentanes plus from gas wells has been processed.

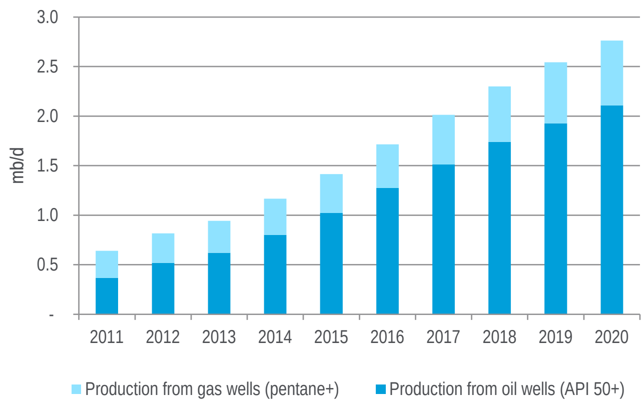
Figure 52. A flowchart on how a surge in US production is having an enormous impact midstream and downstream globally



Source: Citi Research

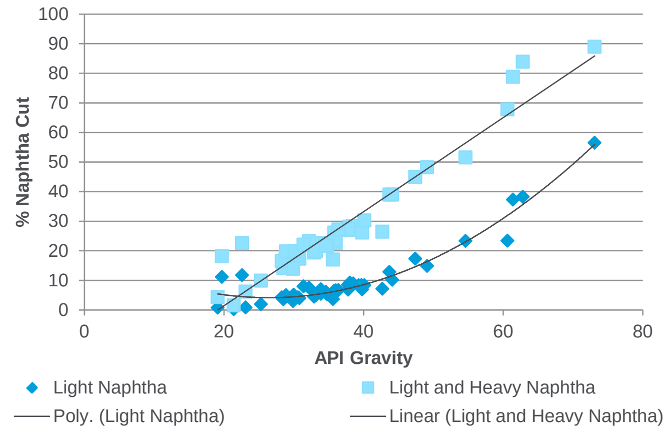
Field condensate production (API gravity 50+) is estimated to rise from about 0.6-m b/d in 2014 to ~1.7-m b/d in 2020. Plant condensate (pentane-plus) production from gas wells is also expected to rise from 0.4-m b/d in 2014 to 0.7-m b/d in 2020.

Figure 53. Total US *condensate* production (plant + field) from oil and gas wells could rise above 2-m b/d



Source: EIA, Citi Research

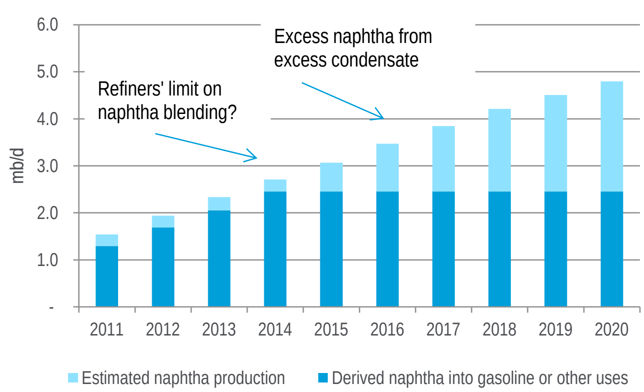
Figure 54. Condensate, with its low API gravity, has a high naphtha cut



Source: Exxon, Citi Research

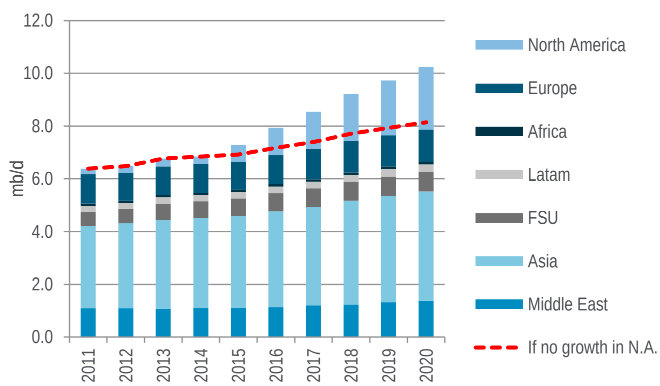
The impact of this surge in condensate production is most evident in the rising supply of naphtha, as condensate typically has a very high naphtha product yield. The total amount of surplus naphtha, which likely could not be absorbed in the US gasoline refining sector, could reach between 1.7- to 2.5-m b/d, which is a massive 20 to 30% of the global market. This happens if all the naphtha produced from different grades of domestically produced crude oil were all added together, particularly ones from lighter oil with API gravity between 40 and 50. **This excess naphtha would eventually enter the overseas market, whether the condensate is processed in North America, blended with heavy oil as a diluent (which would be refined eventually) or exported.**

Figure 55. The US refining system may be close to its limit on processing more naphtha to make gasoline



Source: EIA, Citi Research

Figure 56. More light oil supply leads to more naphtha production



Source: EIA, IEA, FGE, Citi Research

Naphtha is currently the preferred feedstock for the petrochemicals sector outside of the US and parts of the Middle East. Higher supply of naphtha derived from condensates should pressure prices lower, keeping the expanded use of LPG in check. Hence, prices of naphtha and LPG should all be lower.

Too much light, sweet crude oil for the US refining system

One major problem is that the production growth is the wrong kind of oil for the US refining system. The growth of relatively light, sweet crude oil in the United States, which has a refinery system geared to upgrade heavier crude grades that do not yield as much light products such as gasoline without upgrading units, has meant that something has to give: refineries can add capacity to refine light crude, new refineries can be built to process the light crude into light products, or the light crude needs to be exported. Otherwise light US production will fall in value relative to waterborne crude oil in order to incentivize sub-optimal crude slates being run in complex refineries (see pp. 28-31 of "Exit Strategies", Oct 2013) for analysis on the light-heavy crude differential needed for heavy-to-light crude switching). Thus, the refinery system can absorb more light, sweet crude, but this would need to be discounted to back-out secondary feedstocks and cover the worse economics of lower crude throughput and different product yields. All of these processes are currently at work. But the production growth has been far more rapid than either the build-out of refining capacity to deal with it or the accommodation of policy to facilitate exports.

Sometime very soon, possibly as early as 2015, the production growth could be so much greater than either export growth or refining capacity growth the prices could fall relative to world levels, jeopardizing the shale revolution itself **through a reduction in capital expenditures to increase production.**

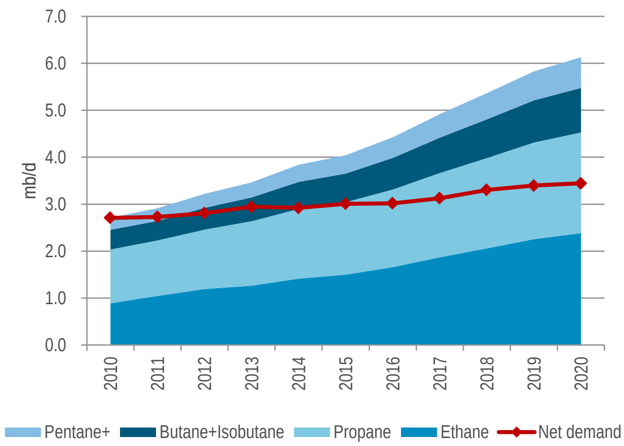
Natural gas liquids (NGLs) production

NGL[1] production has been surging along with crude oil and natural gas and total volumes could almost double between 2012 and 2020, from a total of ~3.2-m b/d in 2012 to 6.1-m b/d by 2020, including both refinery and field production (or from 2.6-mb/d in 2012 to 5.5-mb/d from field production only as stated in Figure 6). Most remarkable is how field production (i.e. not NGLs produced from refinery processes) could rise from 2.6- to 5.5-m b/d over this period. Such stunning growth would be driven mainly by the superior economics of NGL production versus dry gas drilling and production. That is to say, the "next best thing" to oil drilling, if oil prices hold up reasonably well, is NGL drilling. To illustrate, if a "basket" of NGLs were to sell for between $35 to $40/bbl, the revenue from selling dry gas would be ~$23/bbl (assuming a gas price of $4/MMBtu), despite similar production costs. (Gas prices at ~$5/MMBtu are equivalent to about $29/bbl in oil-equivalent terms.)

This could drive NGL exports to grow from 0.6-m b/d in 2014 to 1.6-m b/d by 2020 in the base case, and to 2.4-m b/d by 2020 in the high case, even with higher NGL demand at home in the US from an expanding petrochemicals sector.

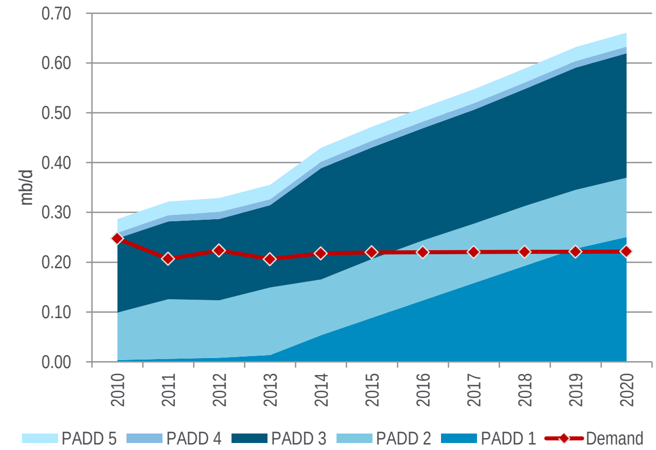
[1] NGLs, or natural gas liquids are produced from natural gas wells, where the "wet" component is processed and "fractionated" to the constituent components, ordered from light to heavy: ethane, propane, butane and pentanes plus.

Figure 57. Natural gas liquids (NGLs) supply growth could far outpace domestic demand by 2020…



Source: EIA, Citi Research

Figure 58. Pentanes plus (or "plant condensate"), effectively identical to field condensate, should see production rising as well



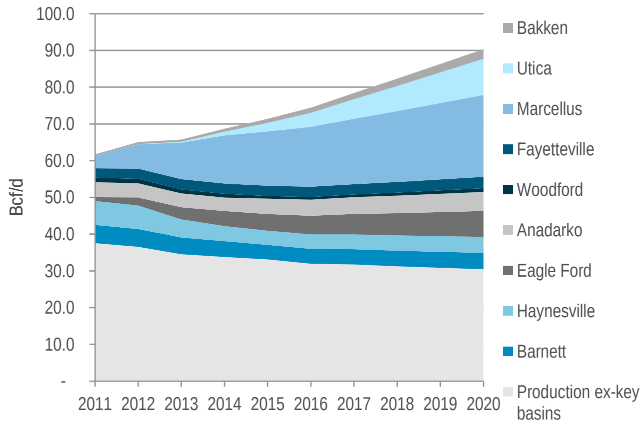
Source: EIA, Citi Research

Can NGLs field production really grow this much? Between 2014 and 2020, production is expected to rise by 2.3-m b/d, which is equivalent to between 8 to 9-Bcf/d in gas-equivalents. By comparison, gas production could rise by 23-Bcf/d in order to meet a similarly-sized demand increase. With producers looking to drill for more wet gas, particularly at the Utica, Southwest Marcellus in the Northeastern part of the US, and Eagle Ford in Texas, the scenario of NGLs making up a quarter of "wet gas" production is entirely possible. Strong oil production growth should also produce some additional NGLs, which could enter into the refinery production part of the ledger, as the oil has to be processed.

Natural gas production

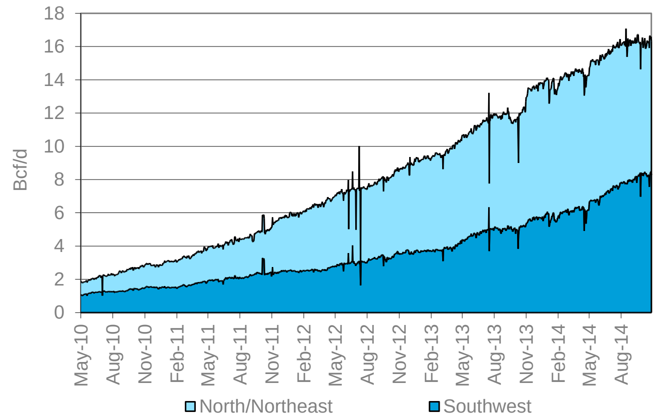
The shale revolution started on the gas side and production improvements are still ongoing. **Production could reach over 90-Bcf/d in 2020, up by nearly 50% between 2011 and 2020.** In particular, gas production from the Marcellus and Utica shales in the US Northeast illustrates the strength of productivity gains. Production from this region has grown from minimal levels to levels greater than most countries globally, falling short only of Russia and the US. As discussed above, technological improvements and learning-by-doing have played an outsized role in boosting production. In addition, the vast reserve size of shale, the associated gas from oil production and robust Canadian gas production are all supportive of continued North American natural gas and natural gas liquids production growth.

Figure 59. Natural gas production could reach over 90-Bcf/d in 2020, up by nearly 50% between 2011 and 2020…



Source: EIA, DrillingInfo, Citi Research

Figure 60. …with a sizeable amount coming from the US Northeast (further broken down into NE Marcellus and SW Marcellus/Utica)



Source: EIA, DrillingInfo, Citi Research

The key to longer term supply stability is the vast expansion of gas reserves in North America, particularly in the US. Shale gas reserves provide much of the rise in incremental reserves, offsetting the slow depletion in other sources. Since 2008, large shale plays in the lower 48 states, including Barnett, Haynesville, Marcellus, Utica, Fayetteville, Woodford and Eagle Ford, have provided more than 90% of the addition in wet natural gas reserves, based on EIA data. If the pace of new shale reserves additions were to continue let alone accelerate, shale reserves could account for more than 50% of the total reserves by end of 2015.

Associated gas from oil production adds to US supply: Gas production from oil and liquids producing wells could make up as much as ~3-Bcf/d per year of the future gas production growth. Associated gas production should remain strong as the US ramps up oil production.

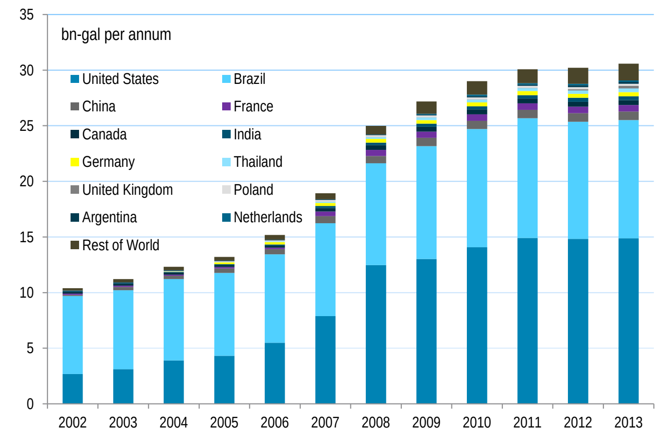
Canadian production also supplements US supply: US gas supply should not be thought of as being restricted to US production, but should also include Canadian production. Canadian gas can still follow its traditional export routes of sending gas to the US via existing pipe infrastructure. A pull from the US would have a positive impact on Canadian prices, pulling them above the price range that should also make gas drilling economics work again in Alberta. Increases in Canadian gas production and exports to the US are highly feasible. The US has a history of importing a much higher amount of Canadian gas and the pipeline infrastructure can support an increase.

Ethanol – US still leads…

Aakash Doshi

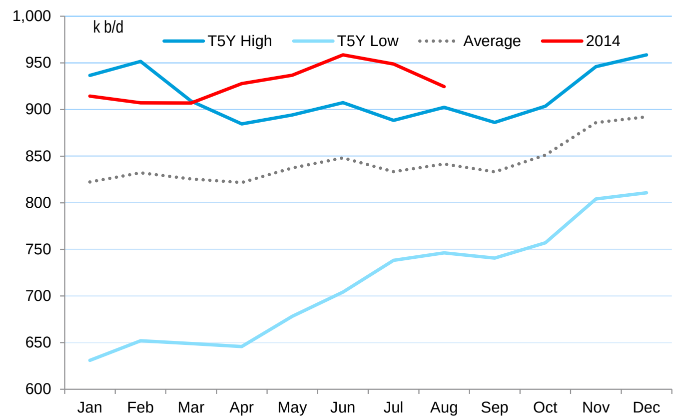
If the shale oil and gas revolution and growth of hydrocarbon liquids were not enough of a boon, the US is also the leading biofuel processor globally. Environmental Protection Agency (EPA) mandates requiring the blending of renewable fuels into the domestic transportation fuel supply have served two critical purposes in the past decade: (1) encouraged production and use of conventional and cellulosic ethanol whereby the US remains the top producer at over 900-k b/d with ~50% of installed world capacity of 30.4-bn gal per year; and (2) displaced traditional motor fuels (i.e., clear gasoline) which have then been made available for export.

Figure 61. Global conventional ethanol production capacity



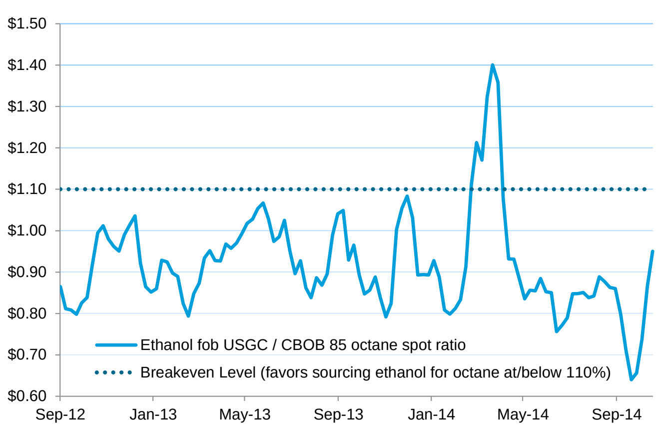
Source: BNEF, RFA, Citi Research

Figure 62. Record US ethanol production is poised to rise in 2015/16…



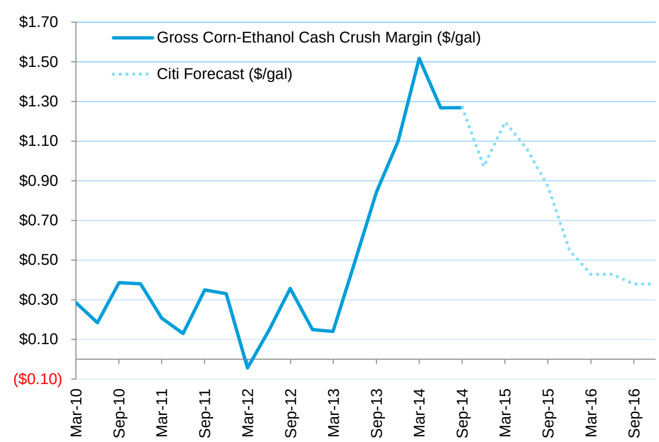
Source: EIA, Citi Research

Figure 63. CBOB-Ethanol blending economics – 'Max out to E10'



Source: Bloomberg, Citi Research

Figure 64. PADD II gross corn-ethanol cash crush margin



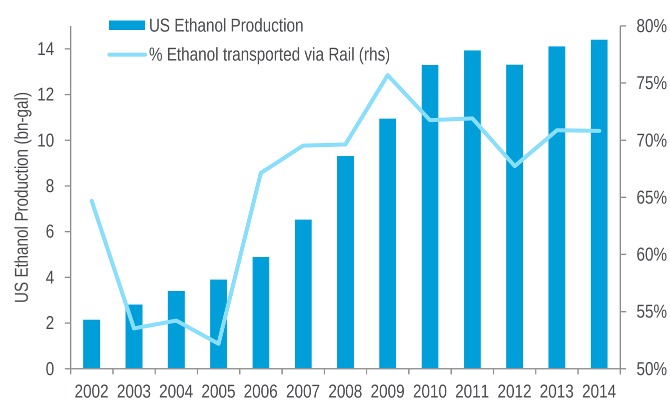
Source: CME, NYMEX, USDA, Citi Research

With record 2014 corn and soybean harvests across the Northern Hemisphere and low row crop prices expected to persist for the next few growing cycles, the outlook for ethanol blending economics and processing margins appears relatively robust versus recent years. This should benefit the US ethanol industry should domestic demand growth ebb due to the E10 'blend-wall' issue as more barrels will be available for export to Canada, Mexico, SE Asia and Europe. However, it is important to note that the 14-fold growth of US ethanol output from the 1990s to present highlights the extent to which domestic refineries have integrated ethanol as a cheap source of octane enhancement and large-scale

oxygenate; essentially replacing MTBE as a gasoline blender net input and placing a hard 'floor' on demand in our view, near an E5-E8 standard. Additionally, by nearly all measures (i.e. cheap feedstock costs, strong domestic absorption, robust export sales demand), US ethanol processors appear to be living through a 'goldilocks' environment and one which we feel is biased to remain in the medium-term.

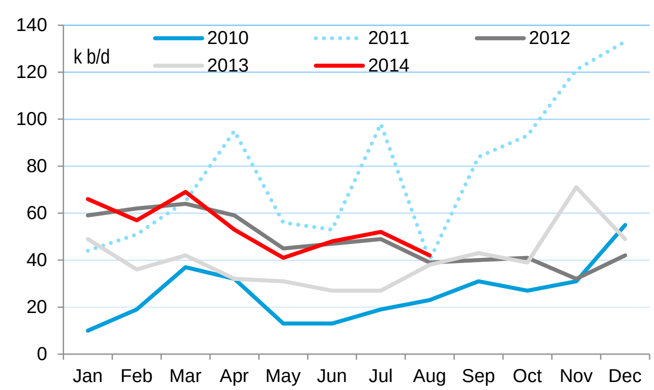
Gross corn-ethanol cash crush margins soared to record levels in the first half of 2014 above $1.50/gal as railway bottlenecks boosted spot bids at US consumer hubs (i.e., NY Harbor and Gulf Coast) and as corn prices started receding from the 2012 drought. Our conservative estimates project processing margins to ease over the next several years, albeit sustainable at lofty levels near or north of $0.40/gal, as corn prices hit a cyclical nadir in the fourth quarter of 2014 before slowly rising again. Ongoing competition among commodities for railcar space also does not rule out potential blow-outs for cash spreads in the coming years, especially during US winter peak export season. But this would only benefit the revenue-per-gallon earned by producers. Considering 70% of ethanol cargo is shipped on land via rail, and given the ongoing growth of US oil output in the Midwest (where 92% of US ethanol is produced but needs to ship to coastal pricing points in the East, Gulf and West Coast Petroleum Administration for Defense Districts or PADDs I, III and V), transportation hiccups and stronger 'freight on board' (fob) New York Harbor (NYH) and fob US Gulf Coast (GC) pricing could be a feature of markets in the years to come — with-or-without a polar vortex winter.

Figure 65. US ethanol production and % transported via rail



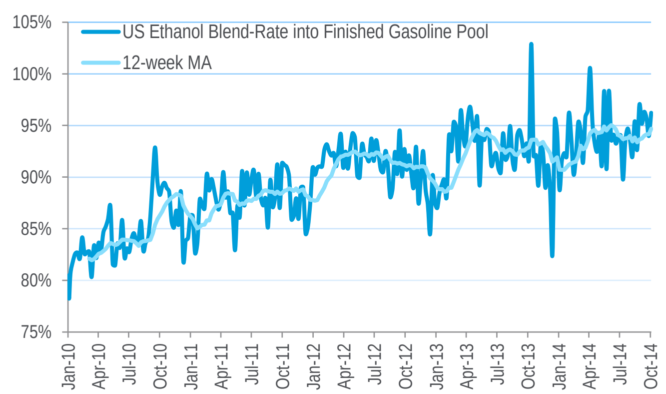
Source: AAR, EIA, RFA, STB, Citi Research

Figure 66. Total US exports of fuel ethanol



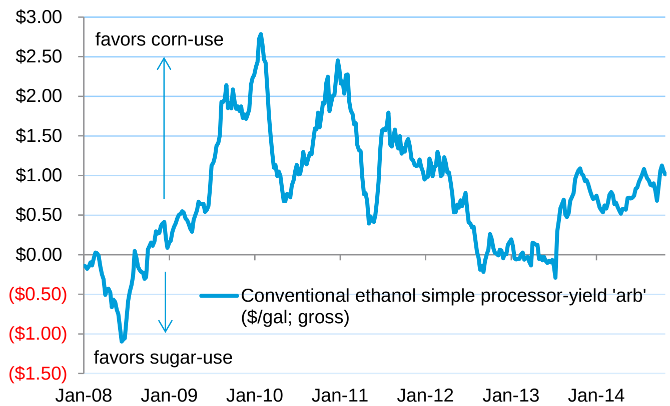
Source: EIA, Citi Research

Figure 67. US ethanol blend-rate into finished gasoline pool



Source: EIA, Citi Research

Figure 68. Corn ethanol yields – favorable versus sugar again?



Source: Bloomberg, Citi Research

Ethanol production capacity utilization has trended higher than the normal 91% and could remain lofty over the next few years since idle plants that can return online are limited. This supports stronger run-rates and initiatives to make existing processors more efficient. To be sure, newer and more stringent greenhouse gas rules are a significant hurdle to expanding US ethanol capacity. Growth in annual ethanol nameplate capacity more than tripled in the past decade to around 15.0-bn gal. By 2020, this figure might only rise to about 16-bn gal per year.

Indeed the elephant in the room is how limited levels of takeaway via E15/E85 mid-level blends can expand. Domestic use of these 'hydrous' blends is likely to remain at only 2-5% of total blender demand over the next several years. That said, US ethanol blend-rates into the final gasoline supply have averaged a record 94% this year and refinery net demand could still grow by a decent 1-bn gal or 7.5% through this decade from 13.3-bn gal in 2014 to 14.3-bn gal in 2020. Particularly if domestic gasoline demand were to surprise to the upside, this would further benefit ethanol producers amid the uncertain outlook for moving beyond the E10 'blend-wall'. With some fifty to sixty renewable fuel standards across the globe, the US also has a clear head-start when it comes to biofuel usage and its export potential could help fill the gap for corn growers and ethanol producers worried about any modest adjustments to EPA blending rules (even though positive economics, not policy, is buttressing the current blending environment).

Figure 69. US ethanol supply/demand balance

(bn-gal; rounded)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Carry-in	0.4	0.4	0.4	0.5	0.4	0.5	0.5	0.6	0.5	0.4	0.4
Production	13.3	13.9	13.2	13.3	14.1	14.4	14.6	14.6	14.6	15.0	15.2
Imports	0.0	0.3	0.5	0.4	0.1	0.0	0.1	0.1	0.1	0.1	0.1
Total Supply	13.7	14.6	14.1	14.2	14.5	14.9	15.1	15.2	15.2	15.5	15.6
US Refinery Input/ Blending	12.9	12.9	12.9	13.2	13.3	13.5	13.6	13.6	13.8	14.2	14.3
Exports	0.4	1.2	0.7	0.6	0.8	1.0	1.0	1.1	1.0	1.0	0.9
Other/ Residual	0.0	0.1	0.0	-0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Demand	13.3	14.2	13.7	13.8	14.1	14.5	14.5	14.7	14.8	15.1	15.2
Ending Stocks	0.4	0.4	0.5	0.4	0.5	0.5	0.6	0.5	0.4	0.4	0.4
Stocks-to-Use (%)	3.2%	3.5%	3.2%	2.8%	3.4%	3.2%	3.8%	3.4%	2.8%	2.4%	2.6%

Source: EIA, UoM, Citi Research

US ethanol exports which were 400-mn gal in 2010, are expected to average around 1-bn gal+ each year from 2014 to 2020. With $3.25/bu maize (and a low US corn cost environment expected to persist for the next several years), Brazilian (sugarcane) ethanol is priced-out on a simple gross-yield basis and sugar prices that have steadied at $0.15-17/lb would probably need to go below $0.10/lb (unlikely in our view). We estimate the 3Q'14 US fob NYH price advantage to Brazil (mill-to-port) north of $0.30/gal and expect that an open 'arb' should remain open for potentially the next several years. In the short-term, with Brazil coming off its peak cane-crush, it is also unlikely its exports (which are down ~35% in 2014) will rebound soon. On the contrary, Brazil has been a top buyer of US ethanol barrels this year; purchases in the first half of 2014 up 166% versus the first two quarters of 2013 with the bias for US volumes to continue to maintain or gain market share.

Renewable transportation fuels such as ethanol are still relatively nascent technologies and only a small portion of the total US energy mix. However, their growth in recent years as blender input, tradable biofuel and the potential for steadying exports in the next decade of some 50-60-k b/d and the fact that the US remains and is poised to stay the leading global grains producer with the cheapest feedstock costs, further buttresses the US case as the foremost liquid fuels producer and energy superpower. Additionally, greater ethanol usage also frees up barrels of neat gasoline or diesel for export, as discussed in other sections.

Evolving US Petroleum Demand: Impacting Trade Flows and Raising Exportable Surplus

The coming expansion in hydrocarbon exports not only involves a hydrocarbon production surge, but also changes in oil and gas demand in North America as well as changes in the utilization and planning for refinery capacity, since obstacles to the exports of crude oil molecules can be overcome by transforming the molecules into petroleum products. Complicating matters is that "demand" has multiple components beyond end-user demand, including refining and other intermediate stages that lead to ultimate demand.

First, there has been a secular trend toward reduced demand, particularly for gasoline and fuel oil. As a result more oil and products would be available for export. Demand for major petroleum products in the US is likely to resume its decline seen since the mid-2000s due to efficiency gains (e.g. improved corporate average fuel economy (CAFE) standards), demographic changes and substitution via greater penetration of hybrids, electric vehicles and natural gas. The lower relative price of natural gas vs. oil, hybrid vehicles and the development of electric vehicles are all working to constrain the demand for traditional petroleum products.

Second, the obstacles to exporting crude oil from the United States have been placing a premium on converting crude to refined products, which can be freely exported. With lower domestic vs. global crude oil prices, refineries are expanding to capture the price difference in crude oil, since petroleum product prices are still largely priced vs. global benchmarks. With shifts in crude oil quality, refineries have to adapt. They are expanding to export more because of attractive margins, but only to the extent that the crude quality matches refiners' capability.

Third, many industrial sectors are taking advantage of lower energy/feedstock costs by changing their processes or increasing capacity. In turn, this results in higher quality products, such as fertilizers and petrochemicals, both reducing imports and entering the export markets.

Transportation fuel demand is stalling out or declining

Changing demographics and efficiencies are driving petroleum demand lower

US demand for major petroleum products fell substantially between 2005 and 2013. Although demand exhibited some year-over-year growth at the end of 2013 and the beginning of 2014, structural changes in demographics, efficiencies of newer vehicles and the emergence of alternative vehicles could drive major product demand lower by as much as an additional 1-m b/d, countered somewhat by continued economic and population growth. Gasoline demand looks likely to fall to 7.9-m b/d by 2020 from 9.0-m b/d in 2010.[2] Our scenario assumes that the adoption of new technology could drive about half the decrease in consumption, with the other half coming from changes in the population make-up and rising efficiency standards. Electric, hybrid and natural gas vehicles (NGVs) could begin encroaching on the market shares of gasoline and diesel engines in a meaningful way within three more years.

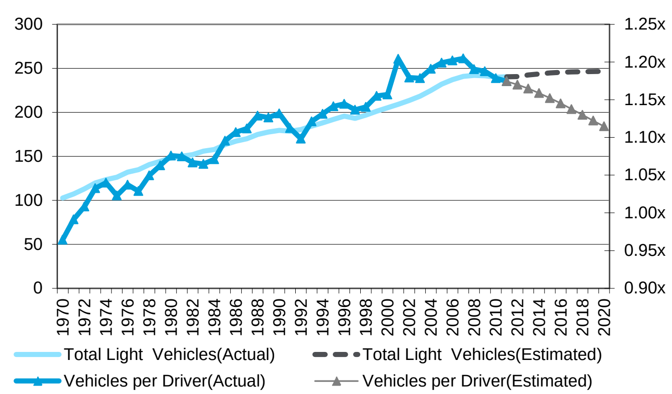
[2] We restrict our definition of heavy duty vehicles to "Truck, combination", "Bus" and "Motor Bus" as defined by the Bureau of Transportation Statistics.

Citi's analysis is based on a number of factors. Directionally, Citi takes the same view as EIA on gasoline demand, but we believe that decline in demand will be larger than EIA's 400-k b/d decline between 2012 and 2020.

Factors driving gasoline demand declines

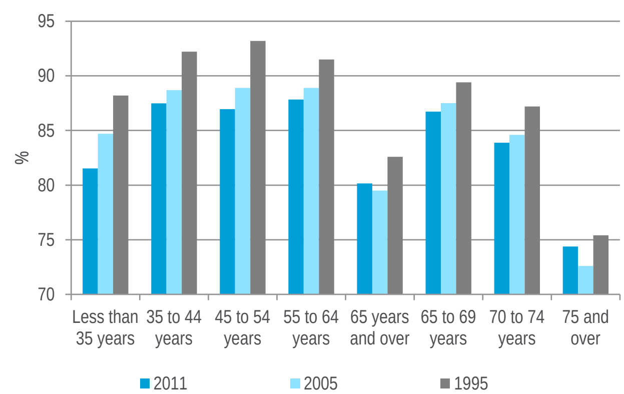
1. **Although the number of vehicles on the road has recently flattened to just over 240 million vehicles, we believe that the subsequent rise in the rest of the decade should be much slower than the healthy pace seen between 1970 and the mid-2000s.** Vehicle density, or the number of vehicles per household, is trending downward, slowing the rate of increase in the number of vehicles on the road and hence liquid fuel consumption. Structurally, from the move to the suburbs requiring additional vehicles for commuting, to shuttling children and the family for various occasions, the need for additional vehicles, perhaps of different sizes, has necessitated more car purchases. But the transition to adulthood for younger members of the family, as well as the retirement of the baby boomer generation, appears to be a significant factor causing vehicle density to fall. A survey by Citi's Autos research team shows how a decline of density appears to be most pronounced for older generations. To counter this decline, vehicle density among younger generations would have to climb to offset the overall drop for the population as a whole. However, housing-related polls seem to indicate a preference for urban living among the younger, Gen-X and Millennial generations and lower vehicle ownership and use than preceding cohorts. The graph below shows how the younger population groups have the fastest decline in motor vehicle ownership rates. In the "less than 35 years" group, ownership rates fell from 88.2% in 1995 to 81.5% in 2011, based on Census data.

Figure 70. Total light vehicles and vehicles per driver (actual and forecasted)



Source: US FHWA, Wards & Citi Research

Figure 71. Motor vehicle ownership rates by age group – fastest decline in the younger population

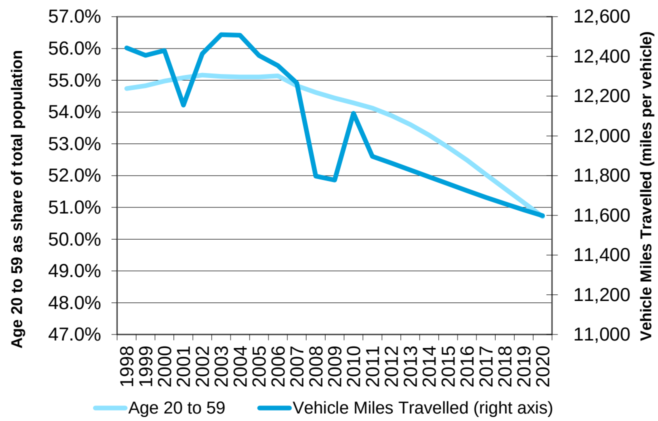


Source: US Census, Citi Research

2. **The increase in the elderly population is resulting in a sizeable change in driving habits, with particular impact on vehicle miles traveled (VMT) per passenger vehicle.** VMT could fall by 4.2% between 2010 and 2020, reaching 11,600 miles/year by 2020. VMT peaked in 2003/04, averaging 12,500 miles driven per year (see figure below). The retirement wave should reduce the need for daily commuting, potentially offsetting the cumulative impact of having longer road trips, if the oldest population cadres undertake trips more often. New habits after the oil price spike in 2008 and the subsequent recession may also have contributed to this change in the amount of driving taking place and

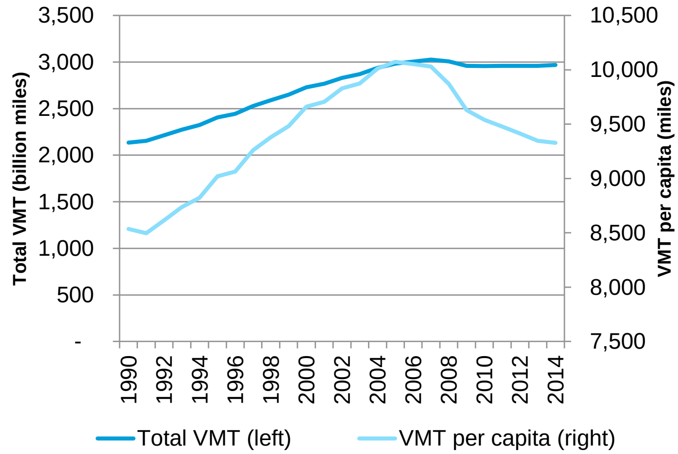
to some degree this could be reversing the downward trends in the years ahead. The net result is a decline in VMT, just as the younger generations preference for urban living, noted above, cuts down the need for longer commutes as well. The graph below shows that the annual total vehicle miles traveled in the US has been flat but trending lower on a per capita basis, from a peak of just over 10,000 miles per year to about 9,300 miles in 2014.

Figure 72. Vehicle miles travelled vs. age 20-59 as share of total population



Source: US FHWA, Wards & Citi Research

Figure 73. Annual vehicle miles travelled in the US has been flat but trending lower on a per capita basis



Source: US FHWA, US Census, Citi Research

3. **Fuel efficiency improvements are accelerating as the CAFE standards tighten.** The national, fleet-wide fuel efficiency could increase by about 0.4 to 0.6-miles per gallon (MPG) every year between now and 2020. Although it appears to be a small number, compared with the more than 1-MPG of annual improvements mandated in new light-duty vehicles sold, raising the average fuel efficiency level of the national vehicle fleet made up of nearly 250 million vehicles would have a sizeable impact. Between 2010 and 2020, the weighted-average fuel economy of the entire fleet nationally could rise by 16%. Along with the 4.2% decline in VMT during the same period, both effects would more than offset the small growth in the number of total vehicles on the road due to population growth.

Natural gas and alternative fuels should also displace oil

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

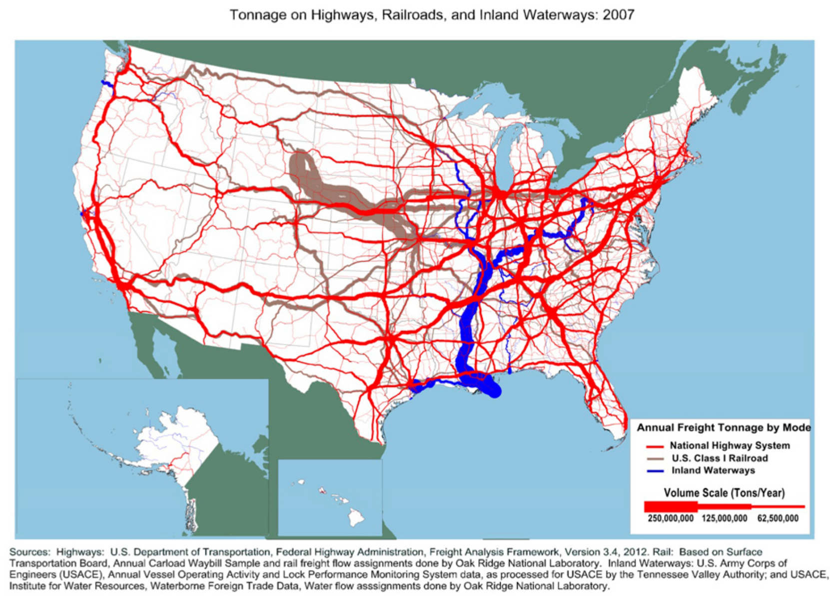
Natural gas could erode oil's dominance in transportation. At present some 16-m b/d of oil is used in transportation in North America. With low natural gas prices, all but aviation provide attractive opportunities for natural gas. The potential conversion to CNG or LNG fuel is quite large. Assuming a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

Additionally, there is a major discontinuity that seems to be emerging when it comes to the historical relationship between diesel demand and GDP. Historically there has been a tight relationship between GDP growth and diesel demand in the US, with every increment in GDP resulting in a 0.8% increase in diesel demand. But this relationship seems to have broken down since 2009. Since then GDP in the US has grown by 2.2% per year, while diesel (distillate fuel oil) demand has slowed to 1.3% per year. This is especially puzzling as along with GDP growth, trucking demand has increased as represented by the increase in the ATA trucking index as well as other indices of trucking demand. The ATA index rose from 114 in January 2011 to just under 130 in mid-2014, or a cumulative average growth rate of 4% per year.

One possible explanation is an increase in diesel engine efficiency. The federally mandated 6% improvement in fuel economy by 2017 takes effect in 2014, which raises heavy-duty truck mileage from ~6.5 mpg to 7.0 mpg. Diesel engines have improved their efficiency correspondingly, and this certainly could be one of the factors behind lagging diesel demand.

Another more powerful explanation might be natural gas substitution for oil. Inroads made by natural gas in transportation may not be captured directly in published data. Trucking activities have increased significantly since the great recession, as per the ATA index. But if diesel demand were relatively flat against the transportation data, it is unlikely the diesel engine efficiency could explain this discrepancy entirely. The only serious alternative is natural gas-powered trucks, where major logistics companies continue to increase the size of their natural gas trucking fleet.

Figure 74. Tonnage on highways, railroads and inland waterways – dominated by a few key routes (2007)



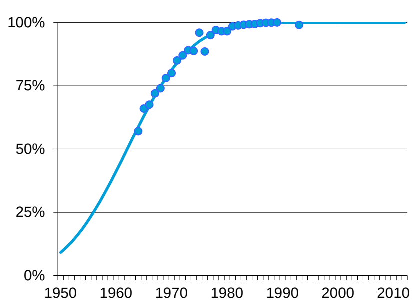
Source: US Department of Transportation

One important factor in natural gas substitution for oil in trucking relates to infrastructure. The infrastructure needed to capture a sizeable portion of the market could be smaller than commonly thought. The map above highlights the major trucking, rail and marine barge corridors, with the thickness of the corridors showing the size of the tonnage involved. There are certain key routes across the country, which dominate freight traffic. Targeting these trucking, rail and marine routes can capture a majority of the market. In the trucking sector, LNG could make inroads in the class 7 and 8 trucks, while CNG can also capture part of the class 3 to 7 segment but even in class 8 trucks in special shorter-haul markets. Light-duty trucks in the class 1 and 2 portion could also convert from oil to gas, particularly for fleet vehicles or ones that have convenient access to CNG refueling stations.

What's more, the adoption of natural gas as a fuel would almost certainly follow an S-curve, with the use of natural gas accelerating as more consumers switch over to the fuel.

By 2020 as much as 0.4-m b/d of demand for transportation could be displaced in the US, freeing up that much diesel fuel for exports. The base case assumes that about 50% of new heavy-duty truck/vehicle (HDVs) sales in the U.S. would be natural gas-powered, in addition to growth of NGVs and natural gas-powered marine transport elsewhere globally.

Figure 75. Diesel's share of new US class 8 truck sales followed an S-curve (1950-2010)



Source: Mackay, Wards Auto, Citi Research

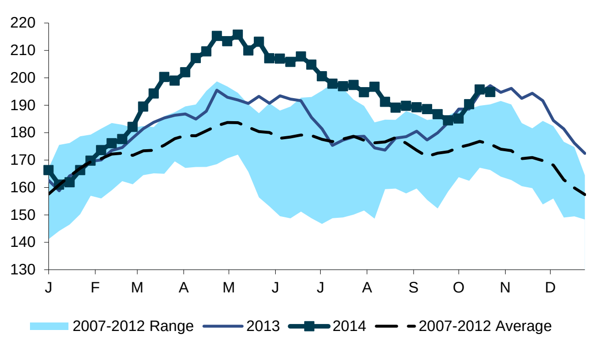
On the Road to Becoming a Global Energy Superpower: Hydrocarbon Exports

With excess hydrocarbon production, the list of exportable items keeps on growing and volume expanding. By taking the path of least resistance, petroleum product exports (gasoline, diesel, etc.) were the first to rise, followed by natural gas liquids (NGLs), condensate and natural gas. What's more, the volume keeps growing as domestic hydrocarbon production rises. The impact of hydrocarbon exports is far and wide.

Refined petroleum product exports set to rise

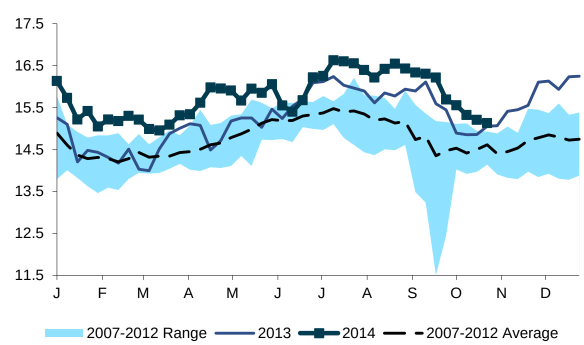
The obstacles to exporting the growing surplus of US light sweet crude and heavier Canadian sour crudes (except to the US) has resulted in a growing conversion of crude oil to petroleum products, which can be freely exported from the US. Hence, this growth of oil and natural gas production has been a boon for those refineries able to access this new cornucopia. Those refineries on the East Coast that had struggled with surging light sweet crude oil prices in recent years have managed to access shale oil from the Bakken and oil sands-derived crude oil from western Canada via rail transportation routes, and have also experienced improved margins. As a result, US refinery margins have benefited (though becoming exposed to the vagaries of the Brent-WTI price differential), and refinery utilization has returned to high levels of 88.3% in 2013 (with glutted PADD II at 98% utilization) versus 86% in 2011 (with distressed PADD I in particular down to the 77% level in the wake of the Libyan civil conflict).

Figure 76. Crude oil stocks in US Gulf Coast (PADD III) region (m bbls)



Source: EIA, Citi Research

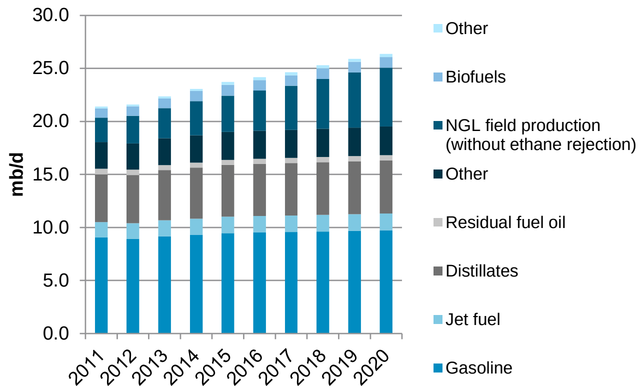
Figure 77. US refinery runs, seasonal basis (m b/d)



Source: EIA, Citi Research

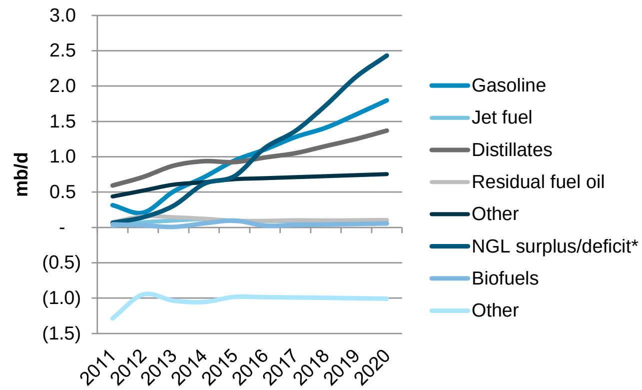
This has had several impacts. Product supply has grown, swelling surpluses, and driving record exports. US production of total liquid fuels has risen from 19.1-m b/d in 2011 to 20.9-m b/d estimated for 2014. With US petroleum demand easing from 20.8-m b/d in 2005 to 18.6-m b/d estimated for 2014, the US petroleum product balance has surged from a deficit of 2.5-m b/d in 2005 to a surplus of 2.3-m b/d in 2014. The lion's share of these exports has gone to Latin America, where robust demand and constrained refinery output have boosted the region's import needs, but other regions like Europe (for distillates) and Africa (for gasoline and distillates) have also imported more US petroleum products. Over the rest of the decade, US refineries benefit from ample crude supply of all different qualities, from light sweet shale/tight oil to medium sour deepwater Gulf of Mexico production to heavy sour Canadian oil sands, as well as low energy costs due to abundant shale gas.

Figure 78. Breakdown of US post-refinery liquids output (2011-2020)



Source: EIA, Citi Research

Figure 79. Exports (imports) of petroleum products and NGLs (2011-20)



Source: EIA, Citi Research

Refinery margins have been boosted by widening discounts of domestic crude relative to global crude prices, though loosening US crude export policy could pull back supernormal profitability. The prices of various North American crude grades became increasingly discounted versus waterborne grades from 2010-2011. At first, this was due to insufficient takeaway capacity away from the landlocked midcontinent, causing WTI prices to discount heavily versus US Gulf Coast prices like Light Louisiana Sweet (LLS). Since the US Gulf Coast was still a net crude import region, LLS prices were typically at a premium to global waterborne prices like Brent.

More recently, new pipelines began to bring inland crude to the coasts, narrowing the WTI discount to US Gulf Coast prices; US oil production began to back out crude imports, and light sweet crude has begun to be in surplus on the US Gulf Coast, causing LLS to lose its premium to Brent, instead moving to a discount to world prices. With policy constraints on crude exports, this weight can continue to act on US Gulf Coast crude grades, including LLS and other crude benchmark prices like medium sour Mars and heavy sour Maya crude. Depressed US crude prices have been a boon for refiners, and while Citi expects US crude oil export policy to loosen, and crude export volumes to rise, US refiners remain competitive versus global refiners.

The product yield of refineries has been shifting too, as the crude slate becomes lighter, meaning greater refinery output of light ends. But with a loosening of crude export policy, the US could export its light sweet crude surplus and continue to import heavier crudes that suit the more complex refineries, particularly on the US Gulf Coast. This would mean the crude slate becomes stable, keeping product yields stable, though continued reconfiguration to boost middle distillate production and keep gasoline production more muted could take place.

Refinery maintenance has always driven seasonality of crude demand. But with restrictions on crude oil exports, the points of the year when crude demand is lowest due to refinery turnarounds are now leading to an exportable product surplus that is trapped at certain times of year and at certain locations. In the fourth quarter of 2013, Louisiana refineries went into heavy maintenance, leading the light sweet crude price benchmark in St James, LA to fall to record discounts to waterborne crude prices – as much as $14 below Brent.

Without growing crude oil exports, light sweet crude prices would discount versus global prices, and versus heavy crude prices. This would help incentivize complex refineries to run light crudes in place of heavy crudes, even with a deterioration of crude throughput and light product yields. It could also encourage light-heavy blending to replace medium crudes. And expansions of light crude processing capacity, such as condensate splitters and topping units, would be economic (see "Mind the Gulf" on price outlooks given various crude export policy scenarios, and "Exit Strategies" on refinery heavy-light switching).

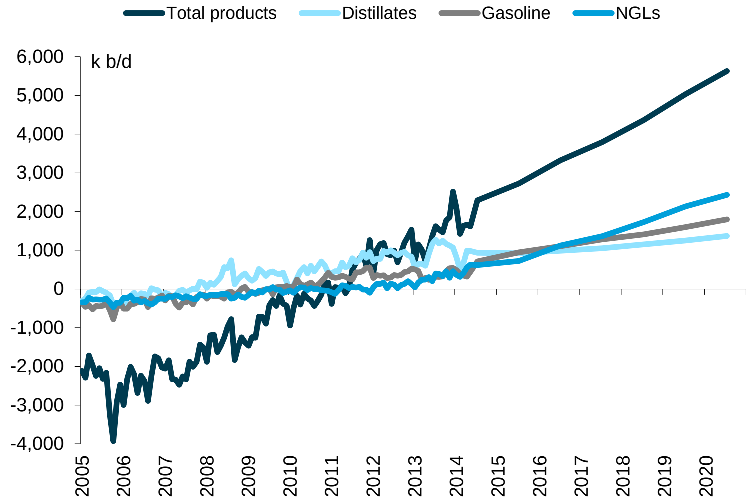
But there are also significant obstacles to growing the refinery base to match increasing US crude oil production. The economics make it difficult for refiners to invest in that much additional capacity. This is especially the case in confronting policy uncertainties with respect to exports of crude oil. Why invest, if the impediments to crude oil exports are going to be eroded? Already there is a significant number of investments in simple refining plants and in condensate splitters which would see economics worsen considerably if US crude export policy were loosened and domestic crude prices rise: this exposes the pitfalls of an export regime that was designed in a different era. With export restrictions in place, refinery configuration may dictate that even large Brent-WTI spreads may not be enough to clean up the glut of light sweet crude in the short- to medium-term, while light-heavy price spreads would also need to compress enough to encourage refinery crude-switching.

With a completely open export regime, light sweet crude prices would reconnect with global light sweet crude prices, meaning refineries would not need to switch away from their preferred, typical crude slate, though like-for-like crude substitution should still occur, with heavy Canadian crude imports replacing Saudi, Venezuelan and Mexican crude imports over time.

Even so, going forward, the exportable surplus of petroleum products should continue to grow. US petroleum product demand can ease from ~19-m b/d in 2013 to 18.5-m b/d in 2020, while refinery output (and NGL field production) can rise from 19-m b/d in 2013 to 20.2-m b/d in 2020. The additional increment of gross product exports from 2013 to 2020 should be about +2.6-m b/d in the base case to +3.6-m b/d in the high case. But the underlying mix of US product demand is wildly divergent – principal product demand of gasoline, jet kerosene, middle distillates and residual fuel oil should fall from 14.2-m b/d in 2013 to 13.4-m b/d in 2020 in Citi's analysis. The difference is that NGLs are absorbed by a rapidly growing petrochemicals sector, with demand rising from 2.5-m b/d in 2013 to 3-m b/d in 2020. This exportable surplus faces intensifying global competition from other petroleum product exporters; refinery capacity is growing quickly in the Middle East, and also in China (albeit at a decelerating rate), and product surpluses are expected to grow.

Citi thinks that it is inevitable that crude oil export policy will loosen from 2015 under a variety of political pressures spelled out in the last section of this report, thus allowing increasing volumes of light sweet crude to be exported, while heavy crudes most suited for the complex refineries on the US Gulf Coast continue to be imported. Thus, refineries need not suffer performance deterioration from running lighter crudes than they are designed for, but growing crude availability of light sweet shale oil as well as heavy Canadian diluted bitumen keeps margins favorable, keeping petroleum product output high, and driving product exports higher.

Figure 80. US petroleum product exports have flipped to net positive and can surge through the decade



Source: EIA, Citi Research

Citi sees net refined petroleum product exports rising from 2.3-m b/d in 2014 to 5.6-m b/d in 2020 in the high case, 4.7-m b/d in 2020 in the base case. This is including NGLs produced from shale plays, for which gross exports could rise from 0.3-m b/d in 2013 to 2.4-m b/d in 2020 in the high case, and up to 1.6-m b/d in 2020 in the base case.

At the time of writing, there could be a buyer announced for the Hovensa St. Croix refinery in the US Virgin Islands, which had been shuttered due to high global crude prices; but access to US shale could change this proposition. In particular, though on US territory, the refinery can receive intra-US waterborne shipments of crude without being subject to the Jones Act; that is it would not require the use of the limited fleet of Jones Act vessels to deliver US crude. This gives it an advantage, and the petroleum products would likely by export oriented. This could drive further upside in US petroleum product exports.

Crude imports backed out: whither Saudi Arabia, Mexico, Venezuela?

The US remains the largest gross crude importer in the world, with China closing in fast, but as shale oil production has grown, import volumes have been backed out progressively; US net crude imports are now only slightly above China's. On top of US shale oil production, Canadian oil sands production has grown steadily at around +200-k b/d per year, and due to paltry infrastructure to the coasts, is captive to the US, which is its main destination market. This has also contributed to less of a need for foreign sources of oil. These trends continue toward 2020, with Canada taking more market share in the US at the expense of Saudi Arabia, Mexico, Venezuela and others.

The consequences for OPEC are severe and growing. Most OPEC countries produce medium to heavy and sour crude oil streams and the refinery system in the US Gulf of Mexico has been the most attractive market in the world for them. But now the loss of market share has become inevitable, increasing competition for access to China's more limited market and weighing on global oil prices. Yet the loss of market share by oil exporter countries has not been straightforward, and instead has been influenced by crude quality (and thus substitutability of US domestic production for imported crudes) as well as the rigidity of term contracts, pricing policy, and supplier-country strategic concerns.

US net crude imports could fall from 7.5-m b/d in 2013 to 3.7-m b/d by 2020, or a drop of 3.8-m b/d. This would be as crude production rises 5-m b/d over 2013-2020 even in the base case. Of these crude imports, Canada represented 2.6-m b/d in 2013, and can increase its market share to over 3-m b/d in 2020, though given the chance, the US's northern neighbor would prefer to export greater volumes of crude oil elsewhere from its west or east coasts. (Canada's westward pipelines remain mired in political wrangling over First Nations rights, environmental, and province revenue-sharing concerns, but its eastward pipeline "Energy East" could be moving 1-m b/d of crude oil to eastern Canada for use there and for export, late in the decade. At the time of writing, a first shipment of WCS crude was exported by Suncor from eastern Canada to Europe, traveling by rail and then ship to Italy.)

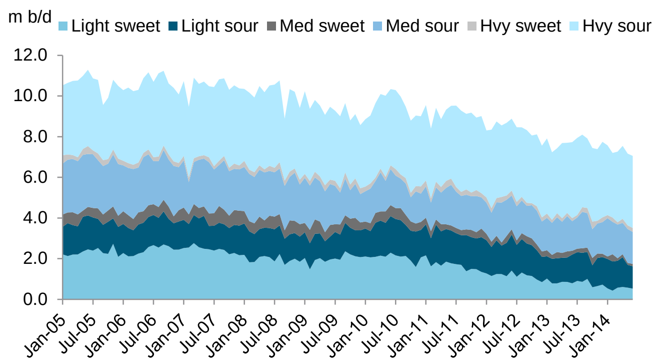
Major base load suppliers Saudi Arabia, Mexico, and Venezuela have been holding on tenaciously to market share in the US, but as US and Canadian heavy sour crude availability rises and prices worsen, these suppliers are already looking to divert volumes elsewhere in order to fetch higher netback prices – the US West Coast, and farther afield to Asia. Smaller oil exporter countries like Iraq and Kuwait may be able to hold on to their market share, but only by accepting lower prices. Other suppliers may fall out of the US market altogether – already Nigeria and Angola have lost practically all market share in the Gulf Coast, with small amounts remaining on the East Coast. Going forward, Colombia, Brazil, Russia, Angola, Ecuador, Iraq, and Kuwait could also see their market share dwindle; Nigerian crude had already been hit hard by substitution by US shale production. Crude barrels looking to find a home elsewhere – and ultimately looking to Asia – can put bearish pressure on waterborne crudes as has already begun to be the case for Brent and the broader Atlantic Basin, for which prices have capitulated since June, despite seasonal summer demand strength and hot, frothy geopolitics in Iraq, Libya, Iran, Nigeria, Russia and Ukraine.

Light sweet crude imports have already plummeted, replaced by domestic light sweet crude from shale plays. The US backed out light sweet crude oil on the Gulf Coast by end-2013, with some volumes still being imported to the US East Coast, and the east coast of Canada. This had been supplied by Nigeria, Angola, Algeria and the North Sea, which have now needed to divert to Asian markets. Light sweet crude was most directly substitutable by the new domestic US shale oil production. The Gulf Coast received more as pipelines extended from Cushing to the Gulf Coast, as well as local supplies from two of the big three shale plays, the Eagle Ford and the Permian Basin, in Texas. The US East Coast received more volumes over time, as the Bakken built out rail loading capacity. And eastern Canada has received more via US crude exports from the US Gulf Coast, but over the next few years, should receive more by pipeline.

Medium and heavy crude imports have been stickier, but supplier countries have had to weather lower prices, while more North American supply of similar quality crudes is on the way too. Light sweet crude imports have dwindled, but light sweet crude availability has continued to rise, driving record crude inventory levels in PADD III. But refiners prefer to run a heavier crude slate, reflected in stable crude imports from medium/heavy crude suppliers.

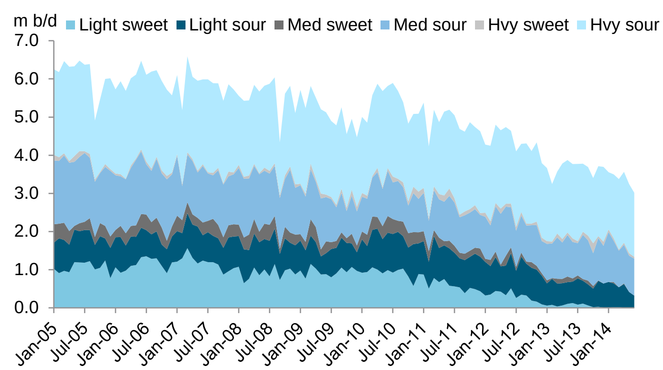
North American supply of medium and heavy crudes is rising. Canadian oil sands production has grown at around 200-k b/d per year on a consistent basis, although the brunt of this has been absorbed by the US midcontinent (PADD II) region to date. But new pipelines should expand capacity along the main lines from western Canada into the Chicago area (including the Alberta Clipper and Line 3 expansion plans over 2015-17), and from there onto Cushing (via the Flanagan South pipeline due in the fourth quarter of 2014 and existing infrastructure), where there is now ample capacity to transit onwards to the Gulf Coast. Add to this growing rail loading capacity in western Canada, and there should be new waves of heavy Canadian crude oil, derived from the oil sands, that arrive in the already crowded Gulf Coast region. Some hiccups to this could come with delays to new pipeline start-ups, as well as bottlenecks further upstream on the Enbridge Mainline, which could mean the 0.6-m b/d Flanagan South pipeline is underutilized in the beginning stages. But even so, this should rise significantly going into 2015-16.

Figure 81. US nationwide crude oil imports by quality (m b/d, 2005-14)



Source: EIA, Citi Research

Figure 82. US PADD III crude oil imports by quality (m b/d, 2005-14)



Source: EIA, Citi Research

And **US Gulf of Mexico production** is projected to rise from 1.3-m b/d levels to 2-m b/d towards 2020, growing at a pace of 150-200-k b/d per year for the next few years, and this should boost medium sour crude supply, as discussed earlier. This means crude-on-crude competition comes to medium and heavier crudes too, not just light sweet crude, which faced competition from close substitutes in the form of shale/tight oil.

Medium and heavy crude prices have already been hit hard since 4Q'13, as falling light crude prices transmitted weakness to heavy crude prices. Louisiana Light Sweet (LLS) and Maya are oft-quoted price markers for light and heavy crudes on the Gulf Coast, respectively; LLS has tended to trade around $5-20 above Maya, but broadly the two prices have moved in a largely parallel fashion. It seems as though the LLS-Maya price differential would have to move consistently to $5 or below in order to incentivize refineries to change their crude slate to running more light sweet crude; the reason is that running a lighter crude in a complex refinery that is designed to run heavy crudes can result in lower crude throughput and lower yields of products, and the price of light sweet crude would have to be favorable enough for the economics of switching to make sense. So far, this signal has not been given, suggesting that either the light sweet crude glut has not been severe enough yet, or that heavy crude suppliers are pricing down to stay competitive. But if the light sweet crude glut becomes untenable, or if a heavy crude supplier seeks higher netback prices elsewhere, say in Asia, then this could cause LLS-Maya to tighten enough to induce heavy-to-light crude switching.

But also, the pricing formula for Maya included a West Texas Sour (WTS) component, which has its pricing point in west Texas, in the prolific Permian Basin, and this benchmark has been hit hard as well. Local dynamics there saw a now-familiar story of fast-growing shale oil production outpacing pipeline takeaway capacity. This led to local prices like WTI Midland and WTS falling versus the widely traded WTI benchmark, which is priced at Cushing, OK. WTI Midland fell to as much as $21/bbl below WTI Cushing in August 2014 before dropping back to sub-$10 levels – typically, Midland traded close to parity with Cushing prior to the fourth quarter of 2011. WTS has fallen to $5-10 below WTI Cushing, having traded at $2-3 below WTI Cushing prior to 2012. In fact, in a sign that light sweet crude is under pressure, while sour crudes remain in demand, WTI Midland itself had fallen to $10 below WTS before coming back to a small discount; this is as opposed to Midland trading at a typical $2-3 premium to WTS, reflecting the higher value for sweet crudes, without infrastructure bottlenecks.

Saudi Arabia exports to the US had held the line at the 1.5-m b/d level even as Gulf Coast prices tanked in the fourth quarter of 2013, but lowered shipments to the US over the summer to the 1-m b/d level as it raised its Official Selling Prices (OSPs) to the US, and now looks set to cut volumes further in the fourth quarter of 2014 and into 2015. Some volumes should remain, to supply Saudi Aramco's JV refineries like Motiva Port Arthur, but aggregate crude export levels to the US could fall to the 0.7-m b/d level in the fourth quarter of 2014 and onwards.

Iraq has seen steady flows to the US so far, but these could begin to wane, although the past months have seen a step up in shipments to the US. **Kuwait** may look to keep its market share in the US for as long as it can, as part of its bilateral relationship and security arrangements.

Mexico has begun shifting lighter sweet crude grades Olmeca and Isthmus to Europe and the US West Coast, respectively, and could come under increasing strain as Canadian volumes reach the Gulf Coast. Meanwhile, its efforts to import US light sweet crude could both lead to higher light product yields at its refineries, as well as relieve the pressure on heavy crudes in the Gulf Coast, helping Maya pricing. On the other hand, if Mexico continues to lower prices to maintain market share in an increasingly crowded Gulf Coast, similar quality Canadian crude can end up being re-exported in even larger quantities. Potential swaps of US light crudes for Mexican heavy crudes under current export rules could add incrementally to US heavy imports.

Venezuela is already looking to shift greater volumes of crude oil to China to repay previous oil-for-loans deals. Meanwhile, with Petróleos de Venezuela (PDVSA) looking to sell its CITGO refineries, term contracts between Venezuela and its affiliated refineries may also be in flux. Despite its massive resources of heavy oil in its Orinoco Belt (now renamed the "Hugo Chavez oil belt"), Venezuela has not been able to develop these resources properly; meanwhile its macroeconomic situation is becoming more and more unsustainable, with national oil company PDVSA footing the bill for massive social expenditures at home, leaving upstream investment woefully neglected. Of Venezuela's declining production then, more of this can shift away towards China, to which it owes supply going forward.

In Citi's outlook, crude export policy is seen to loosen considerably, meaning that the US exports its light sweet crude surplus, and refineries import their preferred heavier crude slate. But Canadian oil sands and US Gulf of Mexico oil production, which are heavier sourer grades, do push out heavy crude imports over time. US gross crude imports can thus fall from 7.3-m b/d in 2014 to 6.5-m b/d in 2020, with over 3-m b/d of this from Canada. (Canada's oil production continues to rise, but pipeline access to its own east coast could begin diverting volumes to world markets from 2018-19, and meaning its ongoing production growth needn't go to the US.) Thus, US crude imports ex-Canada can fall from 5.1-m b/d in 2014 to 3.4-m b/d in 2020.

The unbearable lightness of condensates: increased US exports of condensates look set to sate the world with light products

As discussed in the beginning, small volumes of exports could have BIG impacts downstream: exports of US condensate (or effectively naphtha) and NGLs should have far-reaching implications globally: (1) pressuring global crude oil and gasoline prices, as well as challenging long-held Middle East-based oligopolistic pricing of condensate and LPG as global supply increases; (2) uplifting US condensate and LPG prices as the domestic glut is relieved by exports; and (3) reducing fuel/feedstock costs for global petrochemical and other consumers of light oil. What magnifies the impact of these exports even more is the inter-fuel competition between LPG (and possibly ethane, all components of NGLs) and naphtha, which fight as inputs to the petrochemical sector.

Condensates have been problematic not least because of its uneasy definition in US rules and regulations surrounding exports. Lease condensate (field condensate) is considered "crude oil" in the US crude export regulations, and is treated like crude oil; thus, it can only be exported under a limited set of circumstances. But it is widely understood that NGLs and particularly pentanes plus look much like condensate but have been considered "petroleum products" and thus not subject to crude export controls, and are freely exportable under general license. The largest destination for US crude exports has been Canada, fully allowable so long as the crude is not re-exported as crude oil, with volumes of light sweet crude going to eastern Canada's relatively simple refineries. However, another important sector of US exports to Canada has been condensate for diluent to mix with western Canadian bitumen to enable it to flow in pipelines. This diluted bitumen (dilbit) blend is increasingly being piped back into the US, and these volumes are set to grow substantially as the US pipeline system expands. Now another regulatory quirk is growing – while the US export is recorded as "crude oil", after it is used as diluent, it comes back into the US, functionally as "petroleum product"; but can this dilbit be re-exported from the United States? Not unless there is a clarification on whether the blended condensate has changed its characteristic. The issue is important and may push regulators in the US for a simpler definition of condensate. After all Bakken crude oil, only slightly heavier than what is considered condensate, can also be blended with Canadian crude oil but it clearly cannot be re-exported from Canada or even the US.

There has always been a regulatory arbitrage at play for crude oil exports, of transforming something subject to export constraints ("crude oil"), to something easily exportable ("petroleum products"). When US crude oil moved into surplus and local prices fell, the first step has been for refinery utilization to increase and petroleum product output to rise – this is what has driven the surge in US refinery utilization and in turn in exports of gasoline, diesel and other products. But as that maxed out, and for condensate in particular, another step has been the

use of condensate splitters, which are much simpler distillation units that separate light hydrocarbons into its components, which typically consist of light ends and naphtha. So when Pioneer and Enterprise received clarification in 2014 for whether they could export minimally processed condensate, run through a distillation tower and stabilization unit, this was a further step in looking for yet cheaper ways to transform condensate recognized as "crude oil" into condensate recognized as "petroleum product" (see "Alert: US Condensate Exports"). Given that stabilization units are relatively inexpensive to construct, and already exist at the field level in many places this indicated the potential for much higher levels of condensate exports. Some of this stabilized condensate has already have been shipped to various locations worldwide, including South Korea, and European destinations, too. And volumes are set to grow substantially the existing export approvals are product-specific, not firm-specific and can thus be mimicked by other firms.

Thus as Washington continues to give indications that it could look to loosen the broad crude export regime, condensates too appear to be a key part of the debate. On one hand, it is the area of greatest mismatch between field production and refinery needs. The US Gulf Coast has a complex refinery system that prefers to run heavy sour crudes. And on the other hand, the product yield for light hydrocarbons includes proportionally more gasoline range volumes, which is not seeing much demand growth in the US – indeed, gasoline demand is in secular decline, a pick-up in economic activity notwithstanding.

Several new EIA reports should provide further ammunition for the case for crude exports. The first report, published in May 2014 was on the quality of US crude production, which categorized volumes by API gravity, and showed that the US was increasing significantly its output of 50˚+ API gravity liquids — basically, new US oil production has a meaningful proportion of ultra-light condensates. The second report ("What Drives U.S. Gasoline Prices?"), published in October 2014, argued that US gasoline prices are driven by Brent prices, not WTI prices; thus, higher US crude exports, which could raise WTI prices but lower Brent prices, would lower US gasoline prices, since they are linked to Brent, not WTI. Already, reports from Resources for the Future (a Washington, DC think tank) and the US Government Accountability Office (GAO) have come out which support the view that US crude oil exports would actually lower gasoline prices for US consumers.

Another report may be published in late 2014 on the adequacy of the US refining system in running very light sweet crude oil. These three reports together could make a clear argument that the US is producing a lot more light sweet crude, which is not easily (or economically) processed by the complex US refinery sector on the Gulf Coast, and that exporting this light sweet crude surplus would not cause a spike in gasoline prices at the pump.

World events have also added a foreign policy angle to what had been framed as a "jobs versus the environment" issue; the possibility of US crude exports of condensate blended with a heavy sour crude to make a Urals look-alike is bolstered by the tensions surrounding the Russia-Ukraine stand-off. US sourced condensate would enable both Canadian producers and Mexico to blend up their heavier grades, improving their attractiveness and marketability against Urals crude oil in Europe, something that would provide improvements even without the geopolitical cast such exports would carry.

Citi is optimistic that wider liberalization of crude export policy will take place, and that this should allow condensates, alongside other less light sweet crude, to be exported from the US increased quantities, perhaps as much as 500-k b/d. This outlook underlies the projections that are the basis of this report. Such a picture would mean that US refiners could continue running heavier sourer crudes, and thus still import heavy sour crude, while the US exports its light sweet crude surplus. But whither the condensate export market? As discussed earlier, further down the line, this could lead to oversupply in global naphtha, which could come back to keep light sweet crude prices pressured not just on a North American basis, but a global basis.

Exports of natural gas liquids: small volume but big impact

The impact of US natural gas liquids (NGLs) and condensate exports is global, with the potential to upend existing rigid pricing arrangements overseas and benefiting major consumers of light hydrocarbons. US LPG (propane-butane mix) export capacity should reach ~1-m b/d by 2016, which is ~12% of expected global demand by then, compared with minimal levels just a couple of years ago. Ethane, a hydrocarbon heavier than natural gas but lighter than LPGs, would also be exported as massive expected excess production is leading to construction of ethane export terminals.

How much excess NGLs is there? The difference between total NGLs production and domestic demand should be exportable, and this increment could increase by as much as five times between 2013 and 2020, from ~0.5-m b/d to ~2.6-m b/d. For example, competitive US propane prices versus global prices have attracted substantial planned export capacity. Butane, as a blended component of LPG, should also benefit from the rise in LPG export capacity. **The exports of NGLs, along with condensate, could have far-reaching impact globally across a few sectors.**

Figure 83. NGL supply-demand balance, with large surpluses towards the end of the decade (m b/d)

NGL	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Production	2.7	2.9	3.2	3.5	3.8	4.0	4.4	4.9	5.4	5.8	6.1
Ethane	0.9	1.0	1.2	1.3	1.4	1.5	1.7	1.9	2.1	2.3	2.4
Propane	1.1	1.2	1.3	1.4	1.5	1.5	1.7	1.8	1.9	2.1	2.1
Butane + isobutane	0.4	0.4	0.5	0.5	0.6	0.6	0.7	0.8	0.8	0.9	0.9
Pentane+	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.5	0.6	0.6	0.7
Net demand	2.7	2.7	2.8	2.9	2.9	3.0	3.0	3.1	3.3	3.4	3.4
Production - Demand	0.0	0.2	0.4	0.5	0.9	1.0	1.4	1.8	2.1	2.4	2.7

Source: : EIA, Citi Research

The “supply push” is coming – will it create a “demand pull”? **The export arbitrage is opened up by higher international prices vs. those in the US, even after factoring in the cost of export processing and shipment. The increase in international supply should lower prices globally, but the easing of the US production glut should give US prices support.**
The availability of inexpensive feedstock and energy in the world market due to exports of US NGLs could affect the global market in two ways

First, the delivered costs of US NGLs overseas in Europe and Asia are generally lower than prices of naphtha, propane and other common feedstock. A greater supply of substitutes (in the form of US NGL exports) should loosen the global supply-demand balance and pressure prices lower.

Second, some industries, given lower feedstock costs, would contemplate investing in processes that give them more lasting competitive advantages over competitors using more expensive inputs. The transport costs of shipping North American NGLs overseas also underpins the feedstock price advantages that North American-based industrials enjoy over their competitors elsewhere.

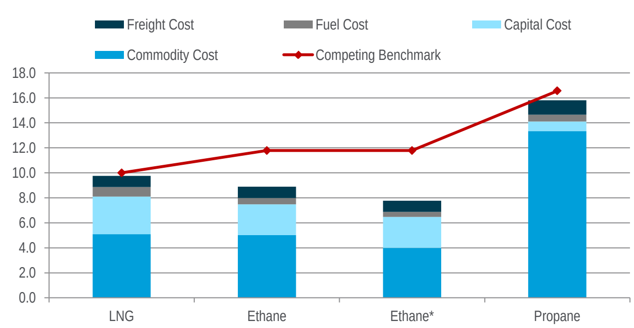
For global petrochemicals in particular, with US NGL exports flooding the world market, higher supply and the resulting decline in international prices should hold down the cost of petrochemical feedstock. This could manifest itself as a negative feedback loop that continually lowers feedstock costs until price differences, adjusted for heat content and uses, are arbitraged away. To illustrate, exports of ethane and LPG (propane + butane) are already having some effect on petrochemical feedstock use; the impact should become even greater as the US exports greater volumes. At first glance, overseas petrochems that use more-expensive naphtha, whose price is linked to oil, face greater competition from petrochems that use ethane and/or LPGs. A deep dive on the impact of US petrochemical sector exports is presented later in this report.

Different impacts on individual NGLs

The ethane surplus in the US is only partially being absorbed by planned US petrochemical crackers. But exports are fast becoming another outlook for excess ethane despite technical challenges and more expensive export processing and shipment costs. Within the US regionally, the ethane production glut is likely to be most severe in the Northeast, and new outbound NGL pipelines to Canada and to the US Gulf, which would connect Marcellus/Utica production to US Gulf Coast petrochem demand, may not be enough to relieve the glut. Waterborne exports could be an effective outlet for excess ethane, potentially superior to ethane rejection.

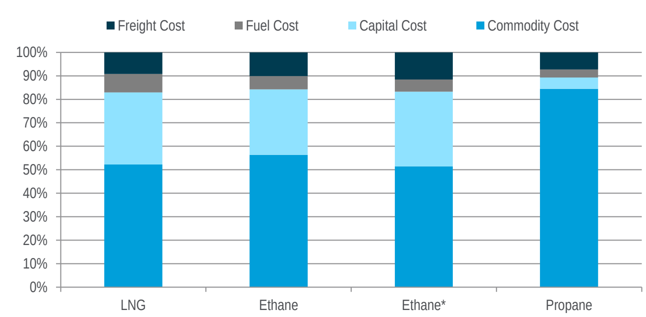
Ethane exports are also a way out of limited opportunities to consume and "reject" ethane. Prices of ethane delivered overseas could be very competitive, especially on an opportunity cost basis for both ethane producers and overseas consumers, thereby incentivizing development of export infrastructure.

Figure 84. Breakdown of cost components by commodity (LNG, ethane, propane)



Source: Bloomberg, Company Reports, Citi Research

Figure 85. Percentage of each cost component in LNG, ethane and propane exports



Source: Bloomberg, Company Reports, Citi Research

Propane production is expected to reach nearly 2.2-m b/d by 2020, while domestic consumption may stay at the 1.2 to 1.3-m b/d level. **This leaves close to 1-m b/d of excess propane to be exported.**

Figure 86. Propane production and demand balance (2010-2020; m b/d)

Propane	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Production	1.1	1.2	1.3	1.4	1.5	1.6	1.7	1.9	2.0	2.2	2.2
Field Production	0.6	0.6	0.7	0.8	0.9	1.0	1.1	1.3	1.4	1.6	1.7
Refinery Production	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Net Demand	1.2	1.2	1.2	1.3	1.2	1.3	1.3	1.2	1.2	1.2	1.2
Net Inputs to Refinery/ Blender	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Product Supplied	1.2	1.2	1.2	1.3	1.2	1.3	1.3	1.2	1.2	1.2	1.2
Diff (Supply - Demand)	(0.1)	0.0	0.1	0.1	0.3	0.3	0.5	0.6	0.8	0.9	1.0

Source: EIA, Citi Research

Compared with ethane, it could be more economic and profitable to export propane internationally to either Europe or Asia. Since the end of the 2013-14 winter Mont Belvieu propane as a key benchmark has been trading ~$1/gal, compared with an equivalent of $1.3/gal in Europe, ~$1.4/gal for the Saudi benchmark and $1.6/gal in the Far East. Shipping costs (capital, fuel and freight) in the $0.20 to $0.30/gal range should yield a positive netback, encouraging exports to Europe and Asia. An increased availability of propane in the international market from US exports would pose direct competition for Saudi-sourced LPG (propane/butane) supply and naphtha as petrochem feedstock.

Given the clear incentive to export, LPG export capacity is expected to expand rapidly, especially in 2015. As of the first quarter of 2014, export capacity was around 400kb/d for LPG and is running at full capacity since the end of 2013. The rest of 2014 should see an additional 110-kb/d of new export capacity come online; export capacity should expand in 2015 by an additional 450-kb/d.

Butane and other higher-value NGLs should also benefit from the lift from exports, potentially putting the NGL basket price closer to ~40% to Brent, up from ~30% in 2012 but still down from ~50% historically.

Natural gas exports: remaking the global order

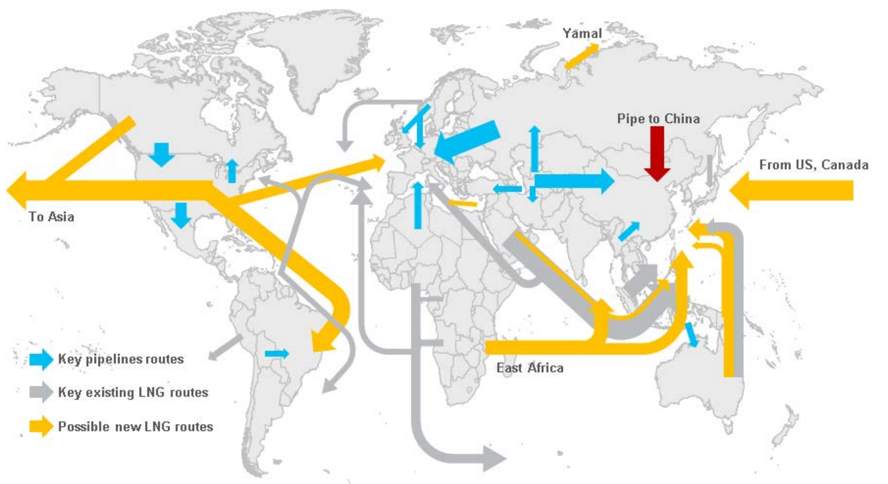
Over the next half decade, the long-held order of global gas supply and demand looks likely to be upended with sharply higher US gas exports on top of higher Australian exports, reversing the fortunes of gas producers and consumers, and altering the existing geopolitical natural gas/LNG balance. The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

It now seems fairly clear that North American exports could be larger than once thought, perhaps even above the initial estimate of 12-Bcf/d (92-mtpa) at the high-end and surpassing Qatar (10.3-Bcf/d or 79-mtpa) and Australia (10.8-Bcf/d or 83-mtpa) by 2020. The Department of Energy (DOE) has already approved nearly 9-Bcf/d (~69-mtpa) of onshore LNG export capacity. Other terminals in the lower-48 states could receive the go-ahead, possibly pushing the total amount of exports to 10-Bcf/d. With potential exports from the West Coast of the US and later Canada or offshore Gulf of Mexico using FLNG (Floating LNG) if the economics work out, total North American LNG exports could easily surpass 12-Bcf/d by the turn of the next decade. And into the next decade 5-bcf/d of exports from Alaska could also be in the works. These terminals should enjoy high capacity utilization: Most of the US liquefaction terminals have very substantive offtake agreements from utilities or global portfolio players.

The US should see net revenue gains from net gas exports. The gas trade balance looks likely to change from -$8 billion in 2011 to +$18 billion in 2020 as a result of LNG exports and exports to Mexico.

What's the size of the global gas market? As the fastest growing major energy source, Citi expects global gas demand to rise from 310-Bcf/d in 2010 to 380-Bcf/d in 2020 for 22% of growth over 10 years, and 470-Bcf/d in 2030, for 51% of growth versus 2010. In comparison, 89.8-m b/d of oil and liquids was consumed in 2012 versus an equivalent of 59.2-m b/d (or 320-Bcf/d) for gas. By 2030, 470-Bcf/d of gas demand, equivalent to about 87-m b/d of oil, could come close to total petroleum demand if oil demand growth were to moderate due to high prices and efficiency.

Figure 87. Map of future global gas flows

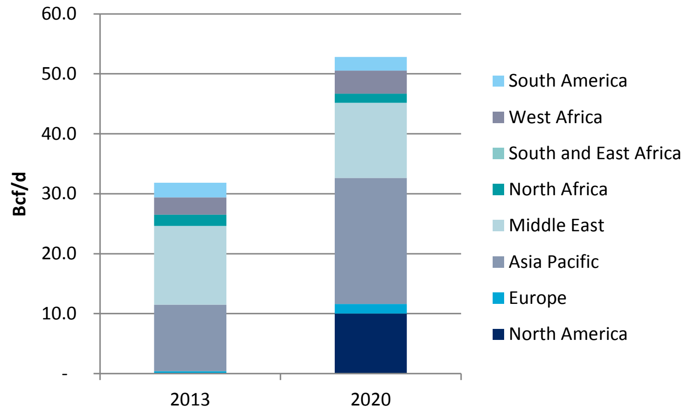


Source: Citi Research
Note: Schematic only; size of arrows not reflective of actual flow; arrow directions indicative only

US LNG exports and the introduction of Henry Hub pricing as the basis of these exports, whose presence is already being felt globally through US coal exports, **could have far-reaching impacts, from (1) bringing gas-indexed pricing to the global market** (instead of the current oil-indexed pricing, where oranges are being priced against apples), **to (2) redrawing global geopolitics**.

First, the rise of the US as an export source will almost certainly facilitate the growth of an LNG spot market, since there will be few impediments on re-sale. A vibrant spot market would create pricing hubs that would significantly erode oil-index pricing globally, reinforcing the erosion set off by pricing LNG exports on a Henry Hub rather than an oil-linked basis. Along with a lack of destination clauses for US LNG, these changes should lead to more trading, transactions and hedging activities, driving the growth of a global LNG spot market.

Figure 88. North American exports to make up nearly 20% of total LNG market – a significant market mover



Source: Wood Mackenzie, Company reports, Citi Research

Second, buyers both in Asia and Europe already see in potential US exports a secure source of supply versus exports that pass through the Strait of Hormuz in the Persian Gulf and those via pipeline from Gazprom. In short it makes a great deal of difference that much of the incremental new supply is coming from OECD countries rather than anti-markets countries like Russia and Qatar. A continued erosion of market power and geopolitical influences impacting existing exporters appears inevitable. Low political risk and gas-indexation of prices appeal to importing countries looking for secure alternatives to oil-indexed gas and leverage for negotiation with LNG suppliers. Almost all US LNG export projects are brownfield developments, with lower costs and shorter construction time, significantly reducing the probability of delays or cost overruns that plague other projects globally. With more US gas exports, global LNG is clearly headed toward more gas-indexed pricing.

Potential high-cost liquefaction projects globally that have not (yet) reached final investment decisions may face more headwinds in obtaining capital, signing contracts and receiving favorable contract terms. Besides the push toward gas-index pricing and away from oil-linkages, the high cost of greenfield projects clearly present greater risks in exploration, production and terminal construction, unlike US or to some extent Canadian projects, which are mostly brownfield and whose back-up reserve sizes are more certain. For details, see "The New American (Gas) Century", particularly section 4.

In addition, gas exports to Mexico are set to surge as pipelines are being constructed across the US-Mexico border. Mexico has a very strong appetite for gas, with the country willing to compete against Asian countries for LNG in the ~$15/MMBtu or above price range, even though cheap US gas is available at the border. **Gas exports to Mexico bring lower electricity prices to the country as well as lower industrial feedstock costs and could reach 5.8-Bcf/d or higher by 2020 versus 1.8-Bcf/d in 2013.** Expanded US supply can drive Mexican gas demand growth, in the petroleum, industrial and power sectors in particular, with the Northeast region feeding gas further into central Mexico.

US exports to its southern neighbor have so far been constrained by (1) capacity in US-Mexico cross-border gas pipelines, (2) internal Mexican gas pipeline capacity and the distribution network, and (3) demand growth from gas-fired power plant expansions, as well as industrial demand. But improvements in natural gas infrastructure across the border and inside Mexico can alleviate this, with major steps in the fourth quarter of 2014 and first half of 2015.

There are several key geographical areas of development for Mexican pipelines: (1) Northeast Mexico, supplying northeast industrial demand, and over time extending into central Mexico. This includes the Los Ramones pipelines, in particular, starting up progressively between end-2014 and end-2015; (2) Northwest Mexico, supplying power plants on the west coast of Mexico, beginning with Sierritas-Guaymas over 2015-16, and the Chihuahua-Topolobampo and Mazatlan pipelines; (3) Central Mexico, expanding the inland gas pipeline system, and adding compressor stations, supplying power generation and industrial demand; and (4) Southeast Mexico, providing greater takeaway capacity for a major gas producing region of Mexico. Areas (1) and (3) can add significant capacity in the near-term. (See "Mexico set to pipe in more US natural gas", Aug 2014)

With the US becoming a more important supplier in the global gas market, many importers would win with increased diversity of supply, while many exporters would lose as competition erodes their bargaining power.

Figure 89. US-Mexico cross-border natural gas pipeline capacity at mid-2014

	Capacity (MMcf/d)	City	State
El Paso Agua Prieta	52	Douglas	AZ
El Paso Mexicana de Cobra	66	Douglas	AZ
El Paso Monument 90, Pemex	30	Douglas	AZ
El Paso Samalayuca Pipeline	545	Clint	TX
El Paso Willcox Lateral	106	Douglas	AZ
El Paso Willcox Lateral Expansion	275	Douglas	AZ
Enterprise Pipeline (fmrly. GulfTerra)	400	Penitas	TX
Kinder Morgan Border Pipeline	350	McAllen	TX
Kinder Morgan Texas Pipeline	300	Roma	TX
Kinder Morgan Mier-Monterrey	425	Salineno	TX
North Baja Exports	600	Ogilby	CA
North Baja Imports		Ogilby	CA
OkTex Pipeline (Oneok)	90	El Paso	TX
Reef International (Tidelands O&G)	15	Eagle Pass	TX
San Diego Gas & Electric/SoCal Gas	350	Otay Mesa	CA
SoCalGas	25	Calexico	CA
Tennesee Gas Ducto Del Rio	374	Rio Bravo	TX
Tennesee Gas Ducto Del Rio (US Imports)	761	Rio Bravo	TX
Tennesee Gas Pipeline	679	Alamo	TX
TETCO-Pemex Interconnect	904	Hildalgo	TX
West Texas Gas, Inc.	25	Del Rio	TX
West Texas Gas, Inc.	38	Eagle Pass	TX
Total export pipeline capacity	5649		

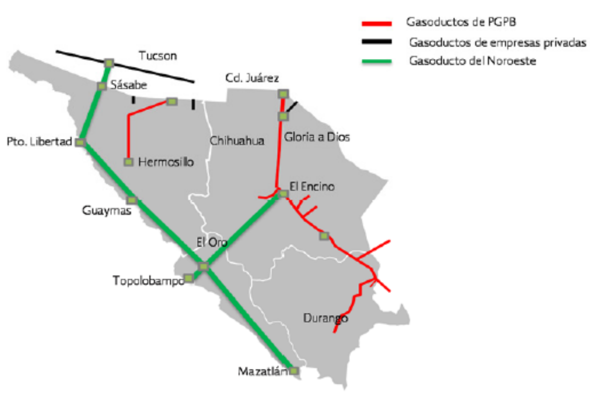
Source: SENER, Bentek, company reports, Citi Research

Figure 90. Future border crossing natural gas pipeline expansions and downstream pipeline capacity expansions

	Capacity (MMcf/d)		Expected
	Border	Downstream	start date
Kinder Morgan Mier-Monterrey expansion	215		Sept'14 to Jan'15
Spectra/TETCO South Texas Expansion/Reynosa	300		2015+
Kinder Morgan El Paso Sierrita pipeline	204		Oct'14
-> Sempra Sasabe-Puerto Libertad-Guaymas pipeline		770	Oct'14
-> Sempra Guaymas-El Oro pipeline		510	Oct'16
El Paso Samalayuca Lateral/Norte Crossing	545		2H'13
-> Energy Transfer/Fermaca Tarahumara pipeline		850	2H'13
-> TransCanada Topolobampo pipeline		670	2H'16
-> TransCanada Mazatlan pipeline		202	2H'16
Los Ramones project			
NET/MGI Agua Dulce-Frontera	2100		Dec'14
-> Frontera-Los Ramones		2100	Dec'14
-> Los Ramones-San Luis Potosi		1430	Dec'15
-> San Luis-Potosi-Apaseo El Alto		1430	Dec'15
Energy Transfer/Houston Pipeline Edinburg Extension	140		Dec'14
CFE Waha-Norte III	1450		2H'16
CFE Ehrenberg-Algodones-San Luis Rio Colorado	130		1H'17
CFE Waha-Ojinaga	1500		1H'17
-> CFE Ojinaga-El Encino		1350	1H'17
-> CFE El Encino-Laguna		1500	1H'17
Inland pipeline/compressor station expansions			
TransCanada Tamazunchale-El Sauz		630	4Q'14
Elecnor/Enagas/Bonatti Tlaxcala-Morelos pipeline		320	2015?
CFE Zacatecas pipeline		20	2H'14?
Altamira compressor station		500	2H'14
Soto La Marina compressor station		430	2H'14

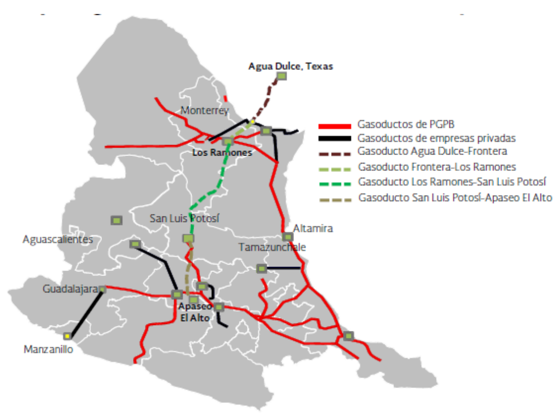
Source: SENER, Bentek, company reports, Citi Research

Figure 91. Northwest region pipeline expansions to serve gas-fired power generation capacity expansion



Source: SENER

Figure 92. Northeast region pipeline expansions serve industrial and power generation demand, as well as extend further into the Central and Central West regions



Source: SENER

Energy 2020: Equity Analysis

Industrial and Petrochemical Demand and Exports

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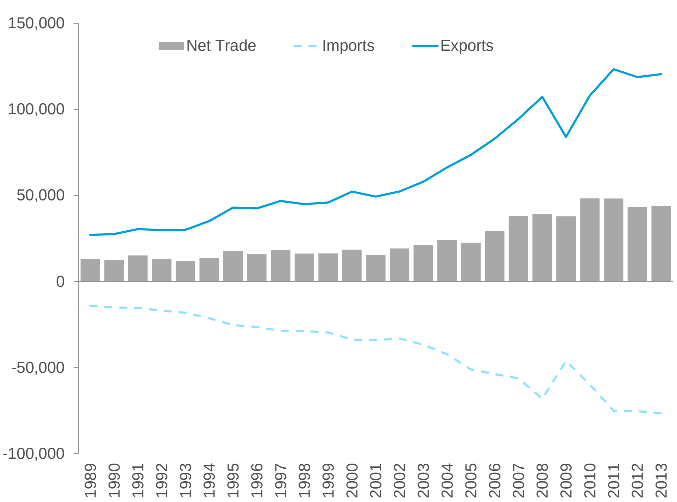
With lower natural gas prices, the increased use of gas as a feedstock and energy source, partly through fuel substitution from both oil and coal to gas, could add nearly 2-Bcf/d of demand across various industrial sectors by 2015 and conservatively speaking 6-Bcf/d between 2013 and 2020. This could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

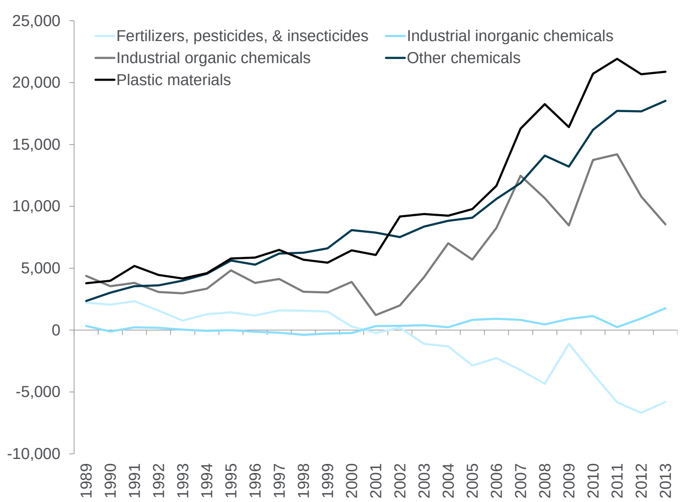
For the subset of projects that we have identified based on public sources, anticipated gas demand growth could reach 4.5-Bcf/d by late this decade and capex around $70 billion. The actual amount of demand and capex should far exceed these estimates, especially if small projects and expansions are included. These projects may also only account for a small portion of the expected gas demand growth due to gains in GDP and industrial production.[3]

Figure 93. US chemicals trade, $ millions



Source: Bureau of Economic Analysis, Citi Research

Figure 94. US chemical net exports by product category, $ millions



Source: Bureau of Economic Analysis, Citi Research

The US Chemical industry has become a more prominent exporter over the past 5-10 years, a trend that is expected to continue over the next 5 years. The American Chemistry Council projects that the surplus in US Chemicals trade, excluding pharmaceuticals, will grow from about $43 billion in 2013 to over $67 billion by 2018, an average annual increase of more than 9%. US exports began to increase during the previous peak in the commodity chemical cycle. The rapid rise in exports was most notable for plastic materials, which nearly doubled from $9.8 billion in net exports in 2005 to more than $18.2 billion in 2008 alongside a peak in oil and petrochemical prices. Plastic materials accounted for about half of US

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

chemical net export growth from 2005 to 2008. Net exports of plastic materials have remained at a higher level than in 2008 despite lower prices for many important products such as polyethylene (PE) used for packaging and films and polyvinyl chloride (PVC) used in construction. We believe this is due to a production cost advantage thanks to lower prices for natural gas, ethane and propane, which are critical raw materials. We expect plastics exports to remain elevated going forward as capacity additions for key building blocks such as ethylene will rely to some extent on exports of derivative products such as PE and PVC. Meanwhile the US has remained a large net importer of agricultural chemicals including fertilizers and crop protection chemicals. For certain products, however, this is likely to change as new plants are built.

A high level of plastics exports is likely to continue due to ethylene capacity expansions given attractive economics. Over the past 5 years the US ethylene industry has progressed through a series of phases, including restarting previously idled capacity and modifying the feedstock capabilities of existing crackers to consume greater quantities of ethane. The industry is now focused on incrementally expanding existing facilities using primarily ethane feedstock. Beyond these brownfield expansions, there are six new ethylene crackers presently under construction and three more in the permitting phase. Each of these firm projects has the potential to commence operations by 2020, the earliest of which are likely to start up in 2017. Many other companies have expressed interest in constructing a new ethylene cracker in the US. We think it is probable that additional US ethylene cracker projects will be announced in the coming years given the expected longevity of the US production cost advantage.

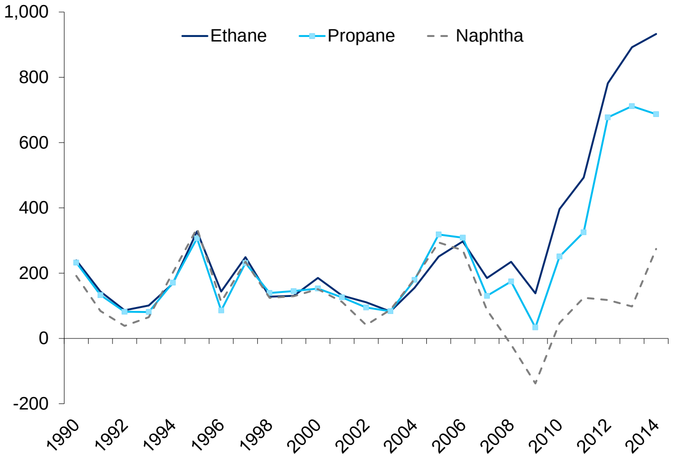
Figure 95. Planned US ethylene capacity additions

Ethylene Capacity (mm lbs)	Location	Status	Derivative Plans	2013	2014	2015	2016	2017	2018	2019	2020
Announced New Crackers											
CP Chem	Cedar Bayou, TX	Under construction	Two PE plants (1.1 billion lbs each)					1,653	1,653		
Dow	Freeport, TX	Under construction	PE, EPDM, elastomers					1,653	1,653		
Exxon	Baytown, TX	Under construction	Two 1.4B lb PE plants at Mt Belvieu					1,653	1,653		
Oxy / Mexichem	Ingleside, TX	Under construction	VCM (sold to Mexichem to make PVC)					600	600		
Formosa	Point Comfort, TX	Under construction	PDH (1.65B lbs) and LDPE (1.25B lbs)						3,500		
Sasol	Lake Charles, LA	Under construction	2B lbs PE; 660mm lbs EO/EG; alcohols							3,307	
Axiall / Lotte	Louisiana	Permitting / FEED	MEG (Lotte); VCM/PVC (Axiall)							1,102	1,102
Shin-Etsu	Louisiana	Permitting	PVC							551	551
Shell	Monaca, PA	Permitting	1.6mmt of PE (high and low density)								3,307
De-bottlenecks / Feedslate Shift											
Westlake - de-bottleneck & feedstock flexibility	Lake Charles, LA			235							
Westlake - de-bottleneck	Lake Charles, LA					235					
CP Chem	Sweeny, TX				200						
Westlake - de-bottleneck & feedstock flexibility	Calvert City, KY				180						
Williams - expansion	Geismar, LA				600						
Dow - expansion & feedstock flexibility	Plaquemine, LA					500					
LyondellBasell - expansion	La Porte, TX				800						
LyondellBasell - de-bottleneck	Morris, IL			100							
LyondellBasell - expansion	Channelview, TX					250					
LyondellBasell - expansion	Corpus Christi, TX					800					
BASF/Total	Port Arthur, TX				420						
Ineos - de-bottleneck	Chocolate Bayou, TX			465							
Other de-bottlenecks				39	37	104	110	0	0	0	0
De-bottlenecks				**1,689**	**2,237**	**1,889**	**110**	**0**	**0**	**0**	**0**
Incremental Capacity (mm lbs)				**1,689**	**2,237**	**1,889**	**110**	**5,560**	**9,060**	**4,960**	**4,960**
US Capacity (mm lbs)				**61,595**	**63,832**	**65,721**	**65,831**	**71,391**	**80,451**	**85,412**	**90,372**
% of US Capacity				2.8%	3.6%	3.0%	0.2%	8.4%	12.7%	6.2%	5.8%
Global Capacity (mm lbs)				**336,653**	**343,843**	**358,664**	**369,846**	**380,787**	**397,602**	**411,777**	**428,312**
% of Global Capacity				0.5%	0.7%	0.5%	0.0%	1.5%	2.4%	1.2%	1.2%

Source: Company reports, Citi Research

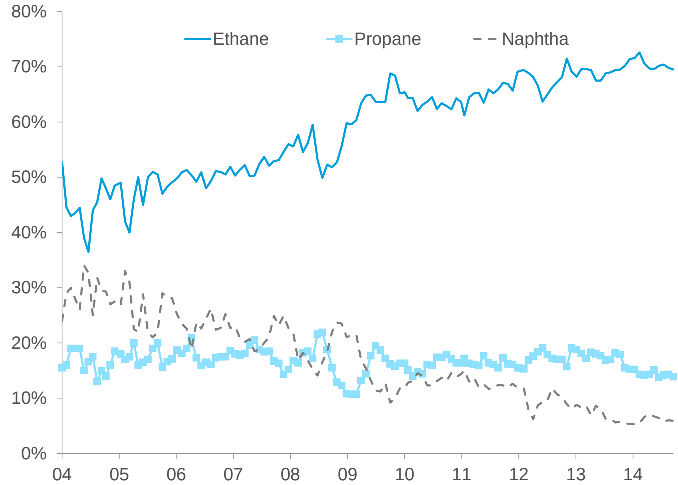
We expect US ethylene margins to remain high for the foreseeable future. Most recently, ethane-based ethylene margins have exceeded $900/mt compared to naphtha-based margins at ~$200/mt. Given the significant margin advantage that ethane (and to a lesser extent propane) provides relative to naphtha, the US petrochemical industry has shifted more production to ethane. Ethane feedstock has been responsible for ~71% of US ethylene production in 2014 compared to ~45% a decade ago. Meanwhile naphtha now accounts for only ~6% of US ethylene production compared to ~30% a decade ago.

Figure 96. US ethylene margins by primary feedstock, $/mt



Source: Citi Research, IHS

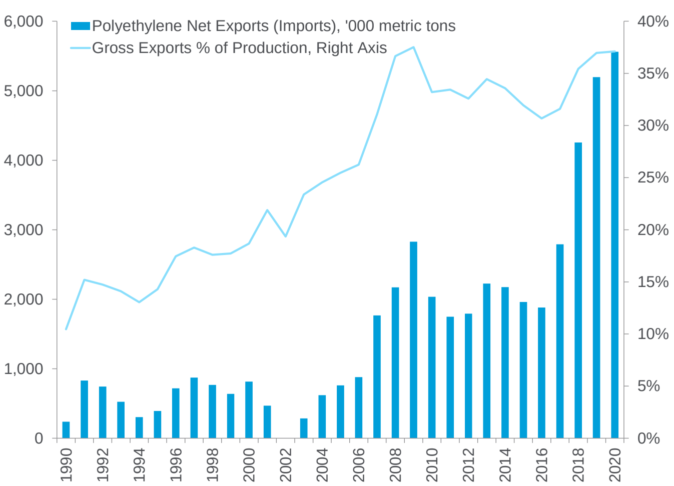
Figure 97. US ethylene production by feedstock, % of total



Source: Citi Research, IHS

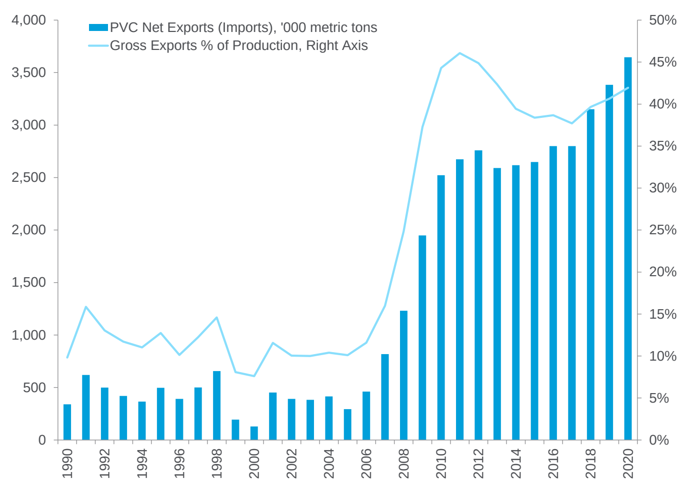
The implication for plastics trade is clear: the US is poised to become a larger exporter of important ethylene derivatives such as PE and PVC over the next 5-10 years. We envision net exports of PE more than doubling by 2020 and anticipate that gross exports will remain near ~35% of domestic production. US PVC exports have reached historic highs in recent years as 40-45% of PVC production has been exported. We anticipate that some of the new ethylene capacity will use PVC as an export outlet, leading to gradually increasing export volumes through at least 2020. A considerable amount of US PE and PVC is currently exported to Latin America, although continued subdued economic growth in important countries like Brazil could result in more exports to the East.

Figure 98. US polyethylene exports



Source: IHS, Citi Research

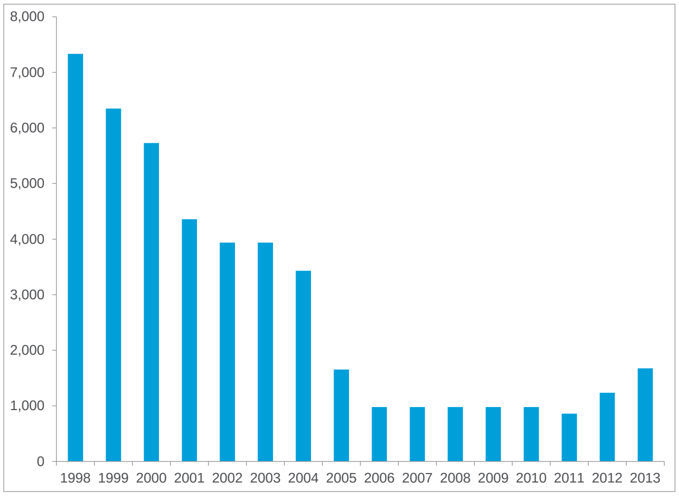
Figure 99. US PVC exports



Source: IHS, Citi Research

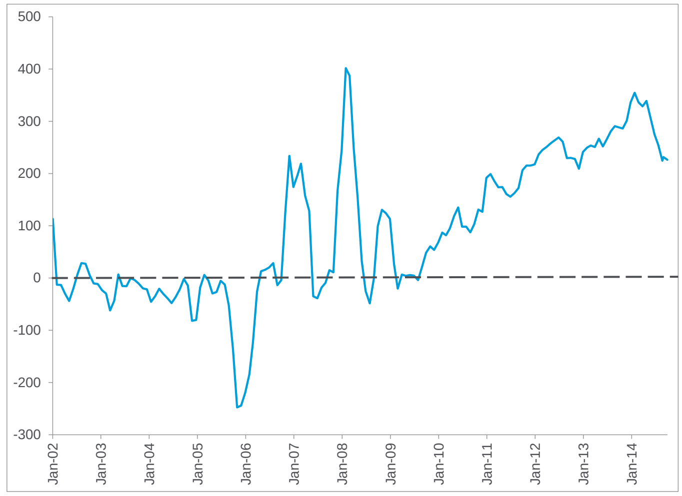
Another key chemical which could see a significant change in US trade flows over the next five years is methanol. Methanol is an important commodity chemical which is used in the production of other more complex chemicals and in energy-related applications. Methanol production capacity in the US experienced a significant decline in the early 2000s, falling more than ~80% before stabilizing in 2006/07. High natural gas prices, the primary feedstock for a majority of methanol produced in the US, made domestic production far less economic than in other regions with cash production margins near breakeven for extended periods during this decade. Natural gas can account for ~80% of cash production costs.

Figure 100. US methanol capacity ('000 mt)



Source: IHS, Citi Research

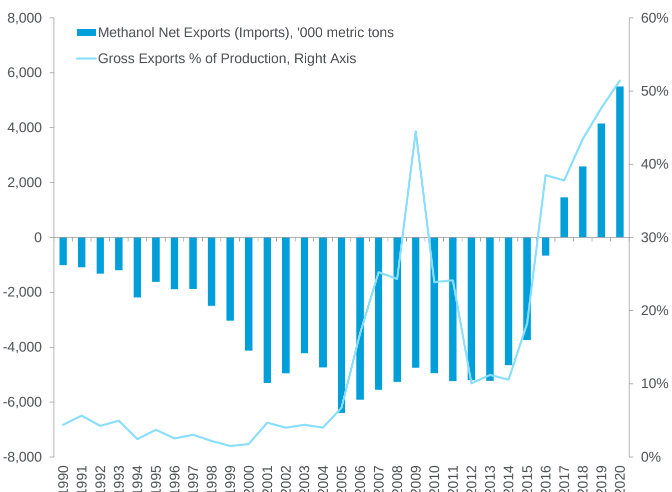
Figure 101. US methanol cash margin ($/mt)



Source: Company reports, IHS, Citi Research

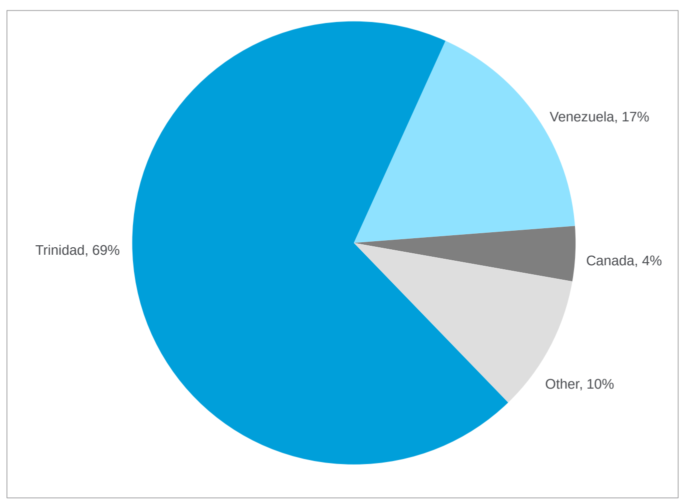
Even before this methanol capacity retrenchment, the US was a net importer of methanol, but this balance significantly grew starting in the late 1990s and continues today. The US has typically imported 4-6mmt of methanol annually over the past decade, with Trinidad accounting for a vast majority of this supply. However, low-cost natural gas in the US, and the expectation of sustained margins which are currently high in a historical context, is poised to result in an infection point in methanol trade.

Figure 102. US methanol exports ('000 mt)



Source: IHS, Citi Research

Figure 103. US methanol imports (2013)



Source: IHS, Citi Research

New investments in local production are well underway. In recent years, LyondellBasell and OCI Partners have restarted previously shut down capacity, while Methanex is both expanding (Canada) and relocating (US) capacity. In addition to restarts and brownfield expansion, there are more than 10 greenfield methanol plant announcements which are in various stages of development. Of these greenfield projects, Celanese is highly likely to be the first to start production by the fourth quarter of 2015. While we do not expect all of these announced projects to be completed, we think enough will start up that the US will become a net exporter of methanol within the next 3-4 years. Already companies are planning for this new trade reality, with Methanex ordering eight new ships for delivery starting in August 2015.

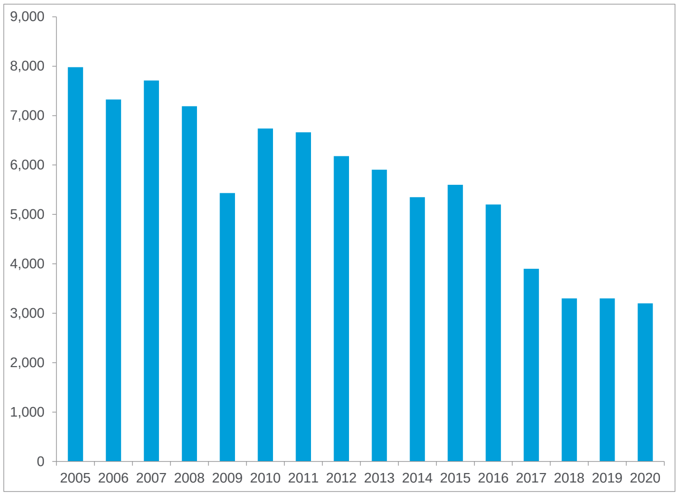
Figure 104. North America methanol project list ('000 mt)

Company	Location	Status	2013	2014	2015	2016	2017	2018
Closures								
Celanese	Bishop, TX							
Celanese	Clear Lake, TX							
Terra Industries	Woodward, OK							
Methanex	Kitimat, BC							
Restarts								
LyondellBasell	Channelview, TX	Complete	780					
Methanex	Geismar, LA	Under Construction			1,000			
Methanex	Geismar, LA	Under Construction				1,000		
Methanex	Medicine Hat, AB							
G2X Energy	Pampa, TX	Under Construction		65				
Expansions								
Methanex	Medicine Hat, AB	Complete	100					
OCI Partners	Beaumont, TX	Under Construction		183				
Greenfield								
Celanese-Mitsui	Clear Lake, TX	Under Construction			1,300			
Celanese	Bishop, TX	Proposal						
Southern Louisiana Methanol	St. James, LA	Permitting					1,600	
Valero	St. Charles, LA	Permitting						1,600
OCI NV	Beaumont, TX	Under Construction				1,750		
Northwest Innovation Works	Port of Kalama, WA	Proposal						1,750
Northwest Innovation Works	Port Westward, OR	Proposal						1,750
Northwest Innovation Works	Port of Tacoma, WA	Proposal						1,750
Yuhuang Chemical	St. James, LA	Proposal						3,000
Fund Connell USA Energy & Chemical Investment Corp	TX or LA	Proposal						
Castleton Commodities	LA	Proposal						
Incremental Capacity			880	248	2,300	2,750	1,600	9,850
North American Methanol Capacity			2,350	2,598	4,898	7,648	9,248	19,098
% of capacity			*37%*	*10%*	*47%*	*36%*	*17%*	*52%*
North America Demand			7,255	7,495	7,629	7,838	8,028	8,276

Source: HIS, Company Reports, Citi Research

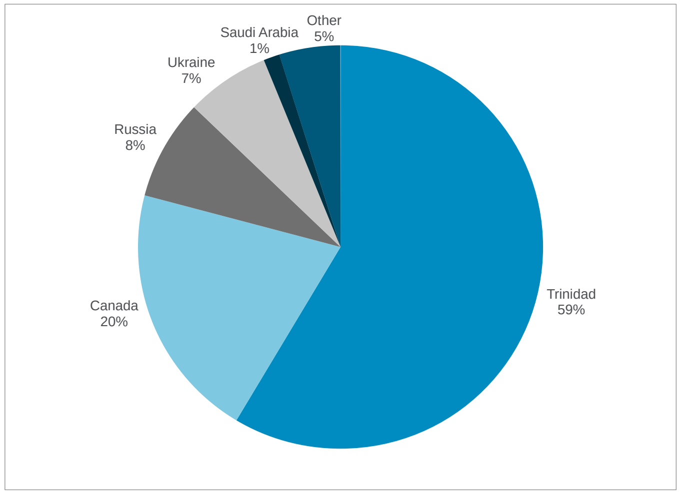
Another chemical which is in the midst of similar trends is ammonia. Ammonia's prime intermediate use is to produce other nitrogen fertilizer products. It exists as a gas at room temperature and can be applied as fertilizer via direct injection into soil with special equipment. Roughly 75% of ammonia consumed in the US is for agricultural purposes, which is less cyclical than some industrial end uses for other chemicals. Other trends in the ammonia industry have many similarities to methanol, including: (1) it is predominately produced from natural gas, which represents a very high proportion of cash production costs; (2) the US is a major net importer of ammonia and its downstream product urea; and (3) a large capacity build out in the US is currently ongoing.

Figure 105. US ammonia imports ('000 mt)



Source: Fertecon , Citi Research

Figure 106. US ammonia imports (2013)



Source: Fertecon, Citi Research

Ammonia imports into the US have already been on a downward trend in recent years. Unlike methanol, in which a majority of US capacity was shuttered in the early 2000s, a sizable base of ammonia capacity remained in the US to service the agricultural market. This allowed for a larger number of relatively quicker brownfield expansions to take place earlier in the shale gas revolution. Since 2010 the US has added ~1mmt of ammonia capacity (~9% growth), predominately through expansions of current facilities and restarts. However, as the first wave of greenfield plants come online in late 2015, the US could further reduce its ammonia imports by another ~3mmt from current levels.

There are two other key features of the ammonia capacity build in the US. First, unlike ethylene or methanol, there have already been several project cancellations by major producers, all citing higher costs. We are seeing reports of labor cost inflation and reduced labor productivity in ongoing projects, which are a risk both to the timing and completion of many of the projects under consideration across the chemical industry. Second, in addition to ammonia, downstream product capacity (such as urea) is also being added in the US. The US is also a large net importer of urea, and thus of the impact of new capacity on trade flows is even larger than just the decline in ammonia imports would suggest.

In our analysis, we believe that at least 13 projects, including five greenfield projects of various sizes, will either have received a final investment decision or will be under construction by the end of 2014. Cumulatively, these projects are likely to add over 5mmt of gross ammonia capacity in North America by 2018 (Figure 107).

Figure 107. North America ammonia brownfield project list

Company	Location	Type	Status	2014	2015	2016	2017	2018
Agrium	Borger, TX	Brownfield	Construction		36	109		
CF Industries	Donaldsonville, LA	Major Brownfield	Construction		289	985		
CF Industries	Port Neal, IA	Major Brownfield	Construction			386	386	
CHS	Spiritwood, ND	Greenfield	Board approved					796
Incitec Pivot	Waggaman, LA	Greenfield	Construction			400	400	
Koch Fertilizer	Enid, OK	Brownfield	Construction				145	
Koch Fertilizer	Brandon, Canada	Brownfield	Construction		81			
LSB Industries	El Dorado, AR	Brownfield	Construction			141		
OCI NV	Lee County, IA	Greenfield	Construction		193	578		
OCI Partners	Beaumont, TX	Brownfield	Construction		40			
Potash Corp	Lima, OH	Brownfield	Construction			80		
Simplot	Rock Spring, WY	Greenfield	Construction			50	150	
US Nitrogen	Greeneville, TN	Greenfield	Construction		66			
Total Capacity Under Construction					705	2,728	1,081	796
North America Ammonia Capacity				17,285	17,990	20,718	21,799	22,595
Growth					*4.1%*	*15.2%*	*5.2%*	*3.7%*
North America Demand				20,610	20,990	22,755	23,680	24,140
Ammonia Trade Balance				(3,325)	(3,000)	(2,037)	(1,881)	(1,545)

Source: Company reports, Fertecon, Argus, Citi Research

If only these projects move forward, North America will remain a net importer of ammonia, although at a slower pace than has been seen historically. However, if three or more world-scale plants currently in the permitting or proposal phase eventually are completed, the US could push out imports entirely or even be a net exporter, although this is not our base case.

Figure 108. North America ammonia project list

Company	Location	Type	Status	2017	2018
Agrium	Nikiski, AK	Restart	Proposal		
AM Agrigen	Killona, LA	Greenfield	Proposal		
Cronus Chemical	Iowa/Illinois	Greenfield	Permitting	800	
Dakota Gasification	Beulah, ND	Brownfield	Permitting	364	
Eurochem	Iberville, LA	Greenfield	Proposal		
FNA	Canada	Greenfield	Proposal		
IFFCO	Bécancour, Canada	Greenfield	Permits Complete		650
Magnolia	American Falls, ID	Greenfield	Permitting		
Midwest Fertilizer Corp	Mt. Vernon, IN	Greenfield	Permits Complete	876	
Northern Plains Nitrogen	Grand Forks, ND	Greenfield	Proposal	730	
Ohio Valley Resources	Spencer County, IN	Greenfield	Proposal		
Summit Power Group	Odessa, TX	Greenfield	Financing		
Yara / BASF JV	Freeport, TX	Major Brownfield	Proposal	750	
Total Capacity of Potential Projects				3,520	650

Source: Company reports, Fertecon, Argus, Citi Research

Infrastructure

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North American Integrated Oil & Independent Refinery Analyst

The existing infrastructure is partly what gives hydrocarbon produced in North America the cost advantage over competitors overseas. We estimate that $185 billion since 2009 has been spent on infrastructure related to tight oil and shale gas production. However, the infrastructure here still has to be augmented by a further build-out in order to bring production to ports for exports. This additional cost per-unit of hydrocarbon produced is small, which helps preserve cost competitiveness, but the sheer volume of production and exports growth leaves substantial opportunities for investments and expansions.

The infrastructure build-out comes in three areas: infrastructure related to the shipments and exports of hydrocarbons; infrastructure related to the development of new oil/gas fields; and infrastructure related to the industrial build-out or expansions of existing facilities.

- **Export terminals of natural gas, natural gas liquids, oil and products** are being expanded or constructed rapidly to take advantage of the large price difference between North America and overseas. Pipes and even roads would have to be built to accommodate increases in exports capability.
- **New fields**, such as the Bakken near the US-Canada border, and even newer fields in traditional producing areas all **need better takeaway capacity**. Further, accessing those fields demand improvements in road access as well.
- **Industrial expansions** and changes in energy/feedstock uses also require **associated improvements in the delivery of capacity of fuels and the send-out capacity**. Although infrastructure expansions for these at the individual project level would not be as large as a major LNG export terminal, so they won't grab as big a headline, collectively the numerous industrial expansion projects would still result in massive infrastructure improvements. (See previous section for a detailed list of key industrial projects.)

This section outlines projects and expansions, mainly for pipelines and rail terminals, as the impact of large natural gas and natural gas liquids terminals is more well-appreciated and is covered elsewhere in this report.

Based on our analysis, we estimate there is over 5-m b/d of dock capacity that is dedicated to the export of all liquid products (refined products, LPG and other liquids) on the Gulf Coast. We estimate this capacity will grow to over 7-m b/d in 2016. The US appears to be moving about 3.5-m b/d out of these facilities, which suggests an almost 70% capacity factor. When one considers the disruptions from weather and ship traffic, we believe the industry is unlikely to run at rate much higher than this. This further leads us to the conclusion that there is approximately another 1.2-1.5-m b/d of dock capacity being built along the Gulf Coast that will accommodate the growth in exports of LPG, refined product, oil and condensate. This is clearly not going to be enough capacity to deal with the growth in all finished products and oil all at the same time. One other possible solution is to use ports on the East and West Coast of the US or even Canada's East Coast. However, transportation to some of these ports is expensive.

- **Oil:** While the concept of exporting crude oil out of the US seems straight-forward and there appears to be growing capacity in the Corpus Christi market to deal with condensate, our research shows that there are significant infrastructure bottlenecks in actually being able to ramp up oil and condensate exports.

Kinder Morgan (KMI), Enterprise Product Partners (EPD), Targa Resources (TRGP), Plains All American (PAA), Oil Tanking Partners (OILT), Buckeye Partners (BPL), Phillips 66 (PSX), Marathon Petroleum (MPC) and Valero (VLO) are some of the companies that have the dock capacity and infrastructure to export various types of petroleum products and other derivatives of crude oil and natural gas (LPG) out of the Gulf Coast. However, in order for crude oil and condensate to be exported, the industry would need to either add more dock space and storage or displace capacity already reserved for LPG and refined product exports. We believe the midstream and refining industry is unlikely to give up its current dock space for finished product exports.

Any large-scale effort to export crude oil and condensate would require new dock capacity and potentially more storage capacity. This capacity could be built by midstream companies but would need to be contracted by upstream players. We think it is unlikely that refiners will build this infrastructure. We also believe it will take at least two years to develop adequate export infrastructure to evacuate the growing supply of crude oil production in the lower 48.

- **Clean refined products:** The US currently exports 3.2-m b/d of clean refined product and other oils. US refiners are continuing to grow this export capacity. With much of the dock space at the refiners dedicated to product exports, we find it unlikely refiners would give up this space for crude oil or condensate exports.

- **NGLs:** With a head start, LPG exports infrastructure is more well developed. The US currently exports 0.4-m b/d of propane and butane and is expected to export 0.3-m b/d of ethane within the next two years. Much of the dock space for these LPG exports is integrated with fractionation capacity which is further connected to broader gathering and pipeline infrastructure nationwide. We believe there is limited excess capacity to push condensate and crude oil through these assets.

Figure 109. US propane export capacity

US Propane Export Capacity						
Existing Facilities &		mb/Month		mb/Day		
Sanctioned Projects	Ship Loadings	Low	High	Low	High	Timing
EPD	MGC, VLGC	7.50	8.50	0.25	0.28	Current
Marcus Hook (SXL)	MGC	0.10	0.10	0.00	0.00	Current
NGLS	MGC	1.00	1.00	0.03	0.03	Current
NGLS	4 VLCG/mo	2.20	2.20	0.07	0.07	Current
Total of Current		10.80	11.80	0.36	0.38	
NGLS	2-4 VLGC/mo	1.10	2.20	0.04	0.07	3Q:14
Mariner East (SXL)	MGC	0.60	1.20	0.02	0.04	2H:14
EPD	3 VLGC/mo	1.50	1.50	0.05	0.05	1Q:15
Mariner South (SXL)	VLGC	6.00	6.00	0.20	0.20	1Q:15
EPD	VLGC	6.00	6.00	0.20	0.20	4Q:15
Total Current + Sanctioned		26.00	28.70	0.87	0.96	
Pending Projects						
Mariner East Phase 2 (SXL)	TBD	-	-	-	-	
Moss Lake LPG Terminal (WPZ/BWP)	VLGC	1.1	2.2	0.4	0.07	End-2015
Total Pending		1.1	2.2	0.4	0.07	
Total Potential		27.10	30.90	0.90	1.03	

Source: US Department of Transportation, Citi Research

- **Natural gas:** A long period of low prices and the very wide price discount between US and global natural gas prices are two key drivers of a rapid development of natural gas export infrastructure**.** The overbuilding of LNG regasification/import terminals, ironically, allowed many brownfield projects which remade these plants as liquefaction terminals which are now contributing to an outlook for US natural gas exports to surge to 10-Bcf/d levels, which could represent a fifth of the potential global LNG market by 2020, alongside similar volumes out of each of Qatar and Australia.

  Implications of North American natural gas exports are far-reaching, from upending the traditional oil-linked gas pricing that prevails in markets outside of North America and Europe, to redrawing global geopolitics. North American gas also has several attractive features, including the brownfield nature of most facilities in lowering overall capital costs, geopolitically stable, supply diversity away from the Middle East, Australia and elsewhere, and the use of gas-indexed pricing etc. These all give importers more leverage vs. their existing gas suppliers. With more US gas exports, global LNG is clearly headed toward more gas-indexed pricing.

Figure 110. List of approved and pending liquefaction terminals in the US

Terminal	Company	Location	mtpa	Bcf/d
Approved (non-FTA)				
Sabine Pass	Cheniere	Cameron, LA	16.5	2.2
Freeport	Freeport/ Macquarie	Freeport, TX	10.5	1.4
Lake Charles	Energy Transfer Partners	Lake Charles, LA	15.0	2.0
Cover Point	Dominion	Lusby, MD	5.8	0.9
Freeport Expansion	Freeport/ Macquarie	Freeport, TX	3.0	0.4
Cameron	Sempra	Hackberry, LA	12.8	1.7
Jordan Cove	Jordan Cove	Coos Bay, OR	6.0	0.8
Oregon	LNG Dev. Co.		9.4	1.3
Pending				
Corpus Christi	Cheniere	Corpus Christi, TX	15.8	2.1
Lavaca Bay	Exelerate	Port Lavaca, TX	10.4	1.4
Gulf Coast	Gulf Coast LNG	Brownsville, TX	21.1	2.8
Southern LNG	Southern LNG	Savannah, GA	3.8	0.5
Gulf LNG	Gulf Coast LNG Export	Pascagoula, MS	11.3	1.5
CE FLNG	CE FLNG	Plaquemine, LA	8.0	1.1
Golden Pass	Golden Pass Products	Port Arthur, TX	19.5	2.6
South Texas LNG	Pangea LNG	Offshore, TX	8.2	1.1
Main Pass	Freeport-McMoRan	Offshore, LA	24.2	3.2
Sabine Pass	Sabine Pass Liquification	Cameron, LA	2.1	0.3
Sabine Pass	Sabine Pass Liquification	Cameron, LA	1.8	0.2

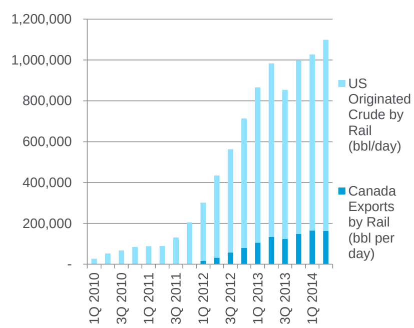
Source: Department of Energy, FERC, Citi Research

Domestic pipeline, rail and processing infrastructure

As much as there is a rapid build-out of infrastructure, the type of infrastructure being built (whether rail or pipe on the oil side) is just as intriguing.

First, the US has been building oil pipelines at a fierce pace, far ahead of any other country in the world. New oil and gas production in North America has led to ripple effects across multiple sectors, not least the midstream sector, which has stepped up to the challenge of evacuating new supply from initially stranded locations and bringing this to market. In 2014, planned pipeline project completions should total almost 2,600 miles of pipe, out of the world's 3,000 miles of pipe, according to the *Oil & Gas Journal* (OGJ). (Note by comparison that natural gas pipelines are being built across various regions in the world. In the same year, the US should build over 1,300 miles of gas pipelines, alongside 1,200 miles in Latin America and 1,700 miles in Asia, out of 5,000 miles of gas pipelines globally.) See "Mind the Gulf" for more details into the infrastructure build-out in the US.

Figure 111. Transport of crude oil by rail



Source: AAR, CAPP, Bloomberg, Citi Research

However, legacy infrastructure was challenged by new patterns of production, which meant stockpiles building where takeaway capacity presented a bottleneck, pressuring prices to discounts wider than pipeline transportation costs. These allowed more expensive means of transportation to come in to evacuate the stranded oil, including trucks, barge, but particularly rail.

Why rail? Optionality. (1) If refineries decide to sponsor new pipe to deliver oil to their facilities, the possibility exists that they might eventually be saddled with relatively more expensive oil and the high cost of new infrastructure if and when new and cheaper sources of oil were found. (2) Even if oil prices were to stay low in North America, the cost of building new pipe may not give refineries that much more of a cost advantage. The reason is that, to take advantage of low crude oil prices in North America, more refineries could be built, thereby raising North American crude prices while possibly lowering global product prices. Despite a narrowing of refinery profit margin, North American crude prices should still remain lower than global prices due to domestic and export infrastructure bottlenecks. The resulting price differential between global and North American prices may be enough to give refiners superior profitability without the need to take on a new pipe. Hence, rail became more desirable.

Importantly, the level and pace of infrastructure capacity build-out has implications for whether production is stranded at times and in certain places, and when and how much refineries on the coasts receive and substitute for imports, or become exportable surpluses.

Impact of infrastructure on US crude oil price differentials

Bakken production can be evacuated in greater volumes by pipeline, but pipelines are not enough to transport all production; the marginal barrel continues to move on rail, meaning a $12-15/bbl discount to light sweet crude prices on the East Coast (landed Brent-related crudes), or the Gulf Coast (LLS, for example). New pipelines should take some share away from rail; these pipelines include the 220-k b/d Pony Express, which started in October 2014.

Permian Basin production should have barely sufficient takeaway capacity even as production grows, though local bottlenecks can be an issue, and local prices can plunge to large discounts versus Cushing and Gulf Coast prices at times. The addition of the BridgeTex line later in 2014, and the Cactus pipeline in 2015, should allow greater volumes to get to the Gulf Coast. The recent reversal of one of the Centurion pipelines to Cushing has also helped a little.

Eagle Ford production is well catered for by pipelines, and is located close to Corpus Christi, TX, in any case.

Refineries

Until recently, US refineries on the East Coast were threatened with closures, partially due to their overall inability to upgrade heavy crudes particularly as the 2011 Libyan civil conflict pushed light sweet crude oil prices higher. But as access to cheaper domestic shale/tight oil production improved with rail transportation of crude, several of these refineries have come back from the dead by running on North Dakotan shale oil, while US East Coast imports of West African crude have virtually disappeared.

With both lower oil prices in North America vs. most places globally, refineries and other oil processing facilities are looking to expand. Such expansions are mostly occurring in the middle of the country from North to South, where the petroleum production “fairway” is. New builds are also happening, such as in North Dakota, where the Bakken field is. The state is seeing an expansion in small-scale refineries that process crude locally, taking advantage of low crude oil prices there by still elevated petroleum product prices. In addition, condensate splitters are also being built, which take condensate (or very light oil) as input and produce simple light petroleum products, such as naphtha and middle distillate, as outputs. While some may question the wisdom of building condensate splitters if condensate exports are allowed, the limited dock space for crude and condensate exports may prevent a larger-scale export operation that the alternative is to turn the condensate into petroleum products before exporting.

Figure 112. Planned and possible US refinery capacity additions

			Existing	2014	2015	2016	2017	2018	2019
MDU/CLMT Dakota Prairie	II	Dickinson, ND			20				
Three Affiliated Tribes, Makoti	II	Dickinson, ND				20			
Dakota Oil Processing	II	Trenton, ND			20				
American Energy Holdings, Bison Oil	II	Devils Lake, ND				20			
North Dakota refinery additions					40	40			
BASF/TOTAL	III	Port Arthur, TX	75						
Kinder Morgan condensate splitter	III	Galena Park, TX			50	50			
Trafigura/Magellan	III	Corpus Christi, TX				50			
Targa/Noble	III	Channelview, TX					35		
Castleton Commodities Int'l	III	Corpus Christi, TX						100	
Chevron	III	Sweeny, TX						50	50
Marathon condensate splitters	II	Canton, OH	22	38					
	II	Catlettsburg, KY							
Martin Midstream Partners LP	III	Corpus Christi, TX							
Marathon	III	Robinson, IL				30			
Condensate splitter additions			97	38	50	130	35	150	50
Valero expand light crude processing	III	Port Arthur, TX		15					
Valero topping unit*	III	Houston, TX				90			
Valero topping unit*	III	Corpus Christi, TX				70			
Valero refinery expansion	III	McKee, TX			25				
NCRA refinery expansion	III	McPherson, KS		15					
Tesoro refinery expansion	IV	Salt Lake City, UT		4					
HollyFrontier refinery expansion	IV	Woods Cross, UT			14				
Western Refining expansion	III	El Paso, TX			25				
Husky refinery revamp	III	Lima, OH							
Alon refinery expansion	III	Big Spring			5				
Rock River Resources	IV	Green River, UT		10					
Worldwide Energy Consortium	III	Eagle Ford, TX				10			
Virtual Engineering Allen Parish	III	Oakdale, LA			20				
Calumet Montana	IV	Great Falls, MT				20			
Expansions				44	89	30			
Total			97	82	179	200	35	150	50
Flint Hills - North Pole				-95					
Closures				-95					

Source: Company reports, Citi Research *Note that topping units are not considered to add capacity on net.

NGLs/gas-related infrastructure improvements

The substantial build-out of pipeline infrastructure and processing plants should continue for years to come, as: (1) producers continue to look for ways to bring gas to market; (2) further upgrades to the pipeline network would have to be made as gas flows are reversed and pipes are upgraded to reduce fugitive methane emissions; and (3) rising oil production not only generates more proposals to convert gas pipelines to oil pipelines, but also prompts more scrutiny in the capturing of associated natural gas that is currently being flared.

Producer-pushed pipeline expansion

Pipeline development will continue as gas production comes online from areas which had not seen substantial gas production previously. Producers should continue to be the main sponsors of new pipelines, as they want to get their gas to price points with decent liquidity, to major existing pipelines for further shipment elsewhere, or directly to major consuming areas.

However, consumers and exporters (or overseas off-takers of US gas or NGLs) may also want to sponsor new pipelines or expansions, so that they can vertically integrate the supply-chain and have direct access to low cost gas/NGLs.

"Last mile" of pipe access to export terminals or industrial facilities

The enormous increase in export capacity, which rightfully grabs headlines due to the hundreds of millions or billions of dollars required, often needs expansions of existing delivery infrastructure. The "last mile" of pipe is often the most crucial but neglected, as a bottleneck would impede export projects from moving ahead in full capacity.

Energy 2020: Macro Analysis

Winners and Losers

Edward L Morse

Global Head of Commodities Research

The transformation of the US from being the largest importer of hydrocarbons in the world to a net surplus country and the potentially the largest exporter of LNG and LPG and refined products is momentous, disruptive and dis-locational. As such it carries winners and losers, some of which can be readily discerned, others remain hidden, some of which are short-term and others significantly longer-lasting.

Geopolitically the consequences are profound, as the impacts on markets have indelibly reduced the pricing power of hydrocarbon exporters that have relied on non-market structures to gain earnings that defy market logic or to exercise influence by using oil and gas exports as instruments of foreign policy. As we have outlined in this report, first the light sweet crude oil producers in OPEC lost the premiums their exports carried over the Brent pricing benchmark, and now the main producers in OPEC are feeling the consequences as well. As the unconventional oil and gas revolution spreads globally OPEC's pricing power will erode even further. In natural gas markets, also as outlined in this report, a similar result will ensue as natural gas's price link to oil is likely to come to an end. One other country, whose domestic market is opaque, China, is also likely to benefit significantly as its power of the purse will be used to lock in supplies from oil and gas producers at the losing end of the balance.

The US is a clear winner, at least for now, and the consequences are wide and deep and long-lasting. When it comes to natural gas and gas liquids feedstock costs – and prices – the economic impact is "permanent" and should easily last at least two generations. This means all energy-intensive industries that use natural gas or natural gas liquids as feedstock have earned an embedded comparative advantage in global markets, from fertilizers and petrochemicals, to refiners, steel manufacturers, cement, paper and other energy intensive sectors. Moreover the benefits will accrue over time as incremental investment flows come to the sectors. Some other consumers of US-based feed stocks also benefit, including manufacturers in China, Korea and Japan in Asia as well as those in Canada, Mexico and Europe. The loss will be for Middle East exporters of LPG's, whose oligopolistic hold on these markets meet competition from the US, already the largest LPG exporter in the world and soon to be larger than all Middle East exporters combined. Global demand will not rise as quickly as US exports, putting pressure on prices and revenues to competitors as a result.

The US exploration and production sector has been and looks likely to be a continual beneficiary overall but winners and losers are likely to be profound among the many independent companies. A recent study by IHS has estimated that the number of jobs supported by the oil and gas production could reach 3.3 million by 2020 and 3.9 million by 2025, up from 2.1 million currently. The unconventional oil and gas sector, along with the petrochemical industry, made up $284 billion of GDP in 2012, which could rise to $533 billion in 2025. The boost to GDP would increase further with multipliers impacting other sectors, including the services industry.[4] And yet the US E&P sector has been highly levered and with lower oil prices the more highly levered companies are unlikely to survive. The industry as a whole has been cash flow negative as the shale revolution has unfolded, with a peaking of capital expenditures exceeding cash flow in 2012 when

[4] IHS, "America's New Energy Future: The Unconventional Oil and Gas Revolution and the Economy – Volume 3: A Manufacturing Renaissance"

the deficit reached more than -$60 billion. That level was cut in half in 2013 and looks to have reached equilibrium in 2014 as the sector moves toward positive cash flow generation above capex in 2015. But what has been true of the industry as a whole is not true of all companies, and some of them, which saw capex reaching 120% of cash flow in a higher-priced environment, will be challenged to survive if capex reaches significantly higher levels of cash flow.

Meanwhile the shale revolution is spreading and the rate of growth of the expansion of shale exploitation globally, even in the face of lower crude oil prices, might be underestimated. While the US approaches 4-m b/d of tight oil production and 40-bcf/d of shale gas output, other countries are trying to benefit from the revolutionary technology as well. Efforts have been successful in Canada and look like they will succeed soon in Mexico as that country's reforms unfold. But Argentina, Australia, China and Russia, all well-established oil and gas producing countries, are actively pursuing shale resource development, incentivized by the US export growth.

The Mexican economy also benefits, ironically as its imports of US natural gas surge even in the face of unfolding Mexican energy reform. The tripling of imports of natural gas from Texas and elsewhere in the United States by pipeline by the end of the decade is driving lower electricity prices and industrial growth in energy intensive industries. Mexico is already the fourth-largest exporter of automobiles in the world, the sixth-largest supplier to the US aerospace industry, and among the top suppliers in the world of flat screens, computers and appliances. It is in the unusual position of being able to tap into lower cost US energy and combine it with low cost labor, to accelerate growth in its manufacturing and services sectors.

Integral to the production and export boom has been the bonanza of opportunities for midstream and ancillary operations in the United States – the construction of pipelines, the expansion of rail, barge and trucking services, in addition to storage, blending, shipping, and LNG/CNG infrastructure (both for trucking and for export).

The impacts on shipping have been more nuanced. The plunge in US imports of crude oil has come at a time when global crude oil trade has stalled volumetrically. On the other hand, the explosive growth in US product exports and the expected sustained growth in US LPG and LNG exports have meant a growing need for smaller and specialized tankers.

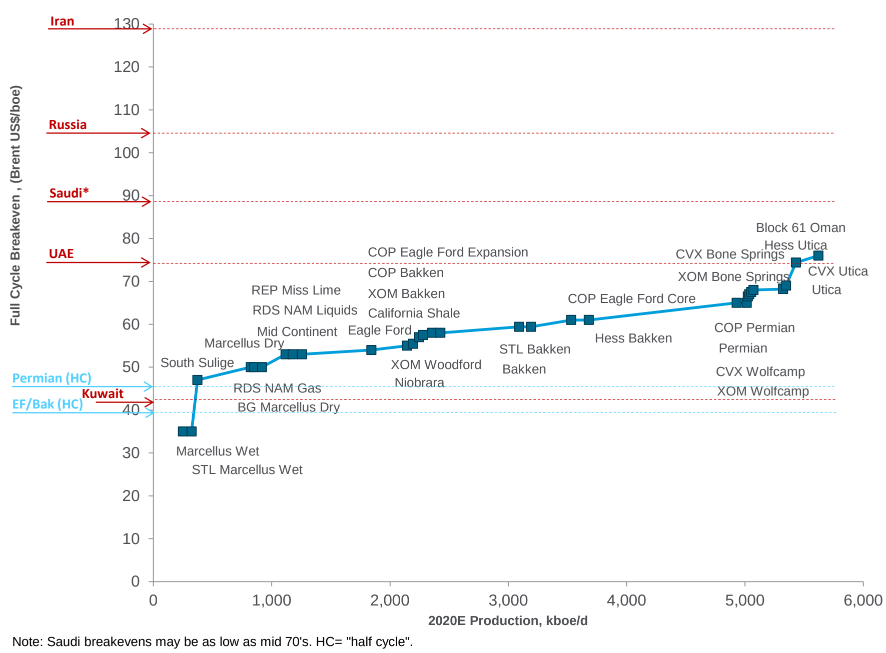
Downstream, as our report makes abundantly clear, refining, fertilizer, petrochemicals and other energy-intensive industries are benefiting strongly. One of the surprising results of the shale revolution has been in refining, with once uneconomic simple refining units, particularly on the US and Canadian East Coasts, turning out to have great value due to the availability of lower cost feedstock. Eventually, depending on how permanent the obstacles to US exports might be, refinery expansion and additions could be expected on both the US East and West Coasts, which are both product short. Indeed, as the US production growth continues and overall light, sweet crude values fall in the Atlantic Basin, even the simpler European plants, such as those in the Mediterranean, might see a rebirth in margins and profitability.

Overall those benefiting also include the "aiders" and "abettors" and the "substitutors." The aiders and abettors include the midstream and other service industries noted above. But substitution also looms larger. There is growing oil-to-gas substitution in road, rail and marine transportation, which is likely to expand rapidly. As well there is coal-to-gas substitution in power generation and greater naphtha and NGL competitiveness in petrochemical feed stocks.

More broadly, globally there are the asymmetric gains and losses to economies that have depended unduly on oil and gas exports and to those who are net importers and users. The pains are concentrated in the oil exporting countries and the gains are dispersed but nonetheless significant in the oil and gas importing countries. Those who are undergoing the severe burden of adjusting to lower prices have greater incentives on the whole to work together to stem the slide than those benefiting from lower costs.

Oil exporters were already under growing strain when crude oil prices remained so steady between 2011 and 2014 as their revenue requirements increased. They are in more critical strain at substantially lower prices. Last year OPEC revenues, excluding Iran which was feeling the pains of sanctions, were a little over $800 billion and per capita revenues were about $2500. A 20% reduction already would, on an annualized basis, cut revenues by $200 billion and per capita revenue by $500.

Figure 113. US shale/tight oil full-cycle breakeven prices of projects to 2020, versus selected oil producer country fiscal budget breakeven oil prices, and half-cycle US shale/tight oil cost levels for the Bakken, Eagle Ford, and Permian Basin ($/bbl)



Note: Saudi breakevens may be as low as mid 70's. HC= "half cycle".

Source: IMF, IIF, company reports, Citi Research

The US petroleum and natural gas sector, meanwhile, is unlikely to undergo a serious challenge. The pain level for producers in the US and Canada are significantly lower than the pain level for OPEC countries, with typical US breakeven costs falling and comparable to the budgetary break-even levels of Gulf Cooperation Council (GCC) countries Kuwait, Qatar, Saudi Arabia and the UAE, and meanwhile the US economy gains as well. While US shale oil full-cycle costs could range from $40-80/bbl, half-cycle costs could be as low as $40-50/bbl (on a Brent basis, with WTI at a discount to Brent). And while Canadian oil sands project breakevens can be up to the $90/bbl level, half-cycle costs are as low as $30/bbl or below. Compare this to the oil prices needed to balance various oil producer country budgets in 2014: Kuwait at $44, the UAE at $74, Saudi Arabia in the mid-$70s but perhaps as high as the mid-to-high-$80s, Russia at $105 (but potentially lower), and Iran at $130/bbl.

Global consumers should also gain form lower costs. If Brent prices normalize in a $80 range the result would be about a $1 trillion boost to the global economy, a massive quantitative easing program for the world. In recent years US household with cars have been spending around $2900 per household on gasoline. If current prices prevail and work their way through gasoline prices, US households should have a one-time effective $600 tax rebate per household, opening up room for spending on goods and services or saving.

Sizeable impact on trade balance, US dollar

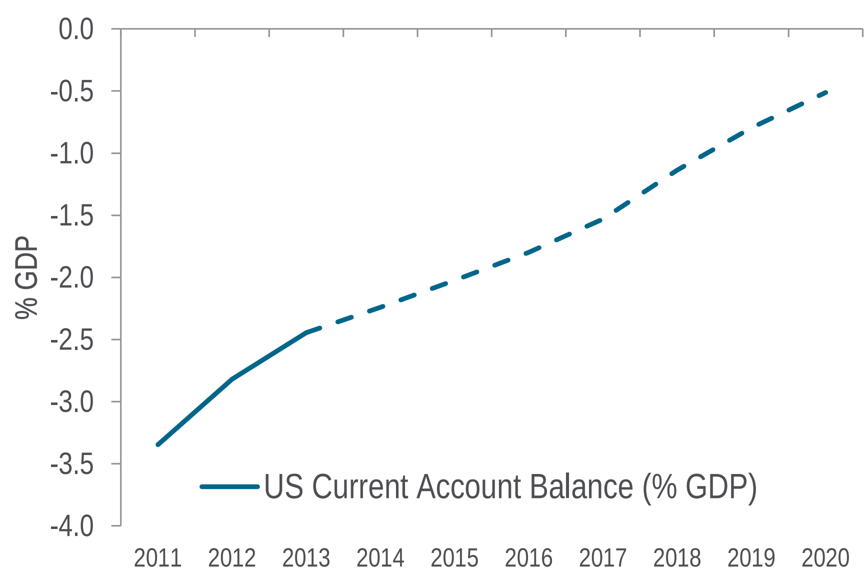
Steven Englander
Global Head of G10 Strategy

The US economy is emerging as one of the most robust globally. Citi's "Energy 2020: North America, the New Middle East" (Mar 2012) first estimated the economic impact of the North American energy revolution. Citi's economics team in the report "Perspectives: Is a Renaissance in U.S. Manufacturing Forthcoming" (May 2013) led by Nathan Sheets looked into the state of manufacturing in the US to date. The report found that "the marked decline in U.S. natural gas prices is an additional spur to competitiveness. We find that this is providing a powerful cost advantage for manufacturing industries that are particularly dependent on natural gas… which together account for one-third of U.S. manufacturing value-added. The boost for other manufacturing industries is notable, but more moderate. We also find that those subsectors with the largest natural gas consumption relative to value-added have been relatively aggressive in their borrowing, presumably with an eye toward expanding their hiring and investment in the years ahead."

This report undertakes another round of in-depth analysis on the current account and other external balances, as well as the impact on the US currency.

The growth in US energy production and exports is likely to take the US current account deficit down to about 1/2% of GDP by the end of this decade – the current level is 2.4%. This is the lowest non-recession current account deficit since the late 1970s. This is a material reduction that greatly reduces US funding requirements and will act to support the US dollar. The move is expected to be gradual, unlike surges or withdrawals of portfolio investment, so the US dollar impact will not be dramatic. However, the cumulative effect is US dollar supportive. By 2020 the 0.5% deficit as compared to the current 2.4% means about $450 billion less need for foreign financing.

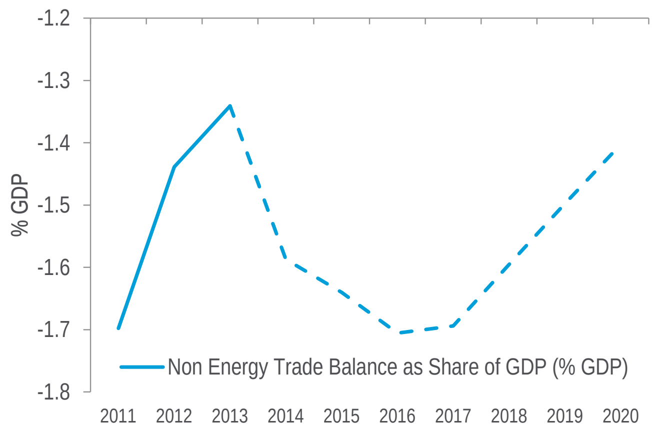
Figure 114. US current account balance (% GDP)



Source: Citi Research

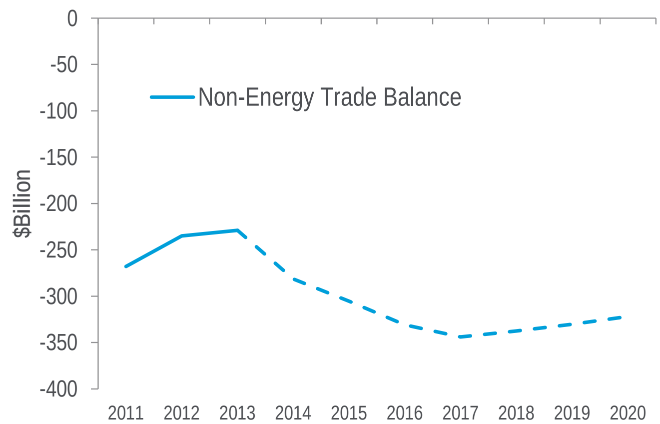
Excluding energy, the rest of the US current account is likely to stabilize in nominal terms and fall as a share of GDP but not as dramatically as the overall current account. The transformation of the energy balance is the biggest likely shift.

Figure 115. Non-energy trade balance as share of GDP (% GDP)



Source: Citi Research

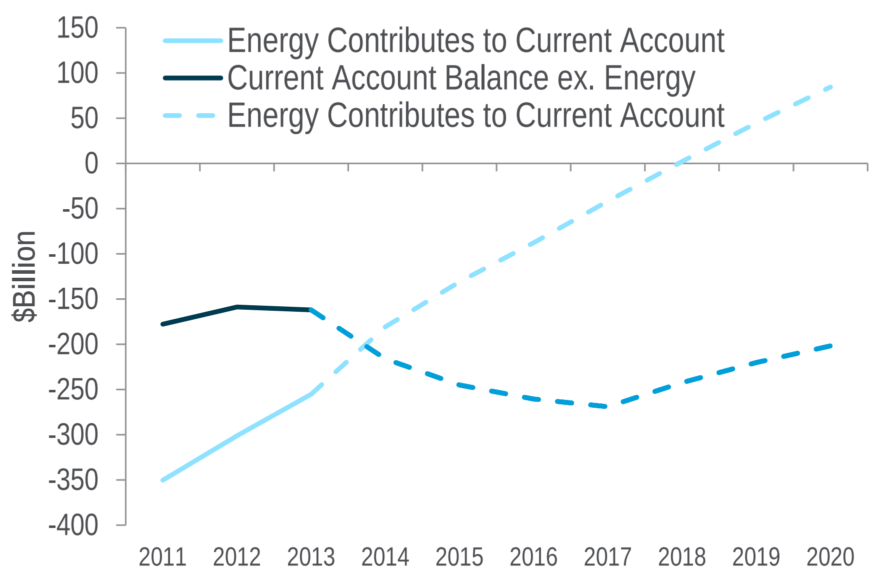
Figure 116. Non-energy trade balance



Source: Citi Research

There are offsetting forces that work to stabilize the current account balance ex energy in nominal terms. On the US import side, we expect the income elasticity of import demand to be 1.25. This means that import volumes will grow slightly faster than US real GDP growth, and imports already exceed export volumes. However, we expect non-energy import price growth to be modest, particularly in imports from emerging market countries so import values are likely to lag US nominal GDP growth.

Figure 117. Energy and non-energy component in GDP



Source: Citi Research

We expect US exports to continue to grow in line with global real GDP growth and US prices. US service exports and many high-end, branded goods have low price elasticities, so it is likely that export prices will be in line with US prices. We would see some risk that export volumes grow slightly faster than foreign GDP, but that price growth is somewhat slower than US GDP growth.

Transfers have been stable for some years and we do not see any big change in the next year or two followed by modest growth.

The income balance is a function of US interest rates, the US dollar, and asset market returns abroad. Our economists expect US rates to rise but relatively slowly and not dramatically, so the debit side on the income balance will rise slowly. We see cyclical US dollar strength in the next couple of years, followed by stability so translation effects will likely be negative this year and next. Overall the next year or so could see softness of receipts followed but is likely to be followed by a gradual pickup in line with growth abroad.

Implications for the US Dollar

Some current account improvements are better than others for currencies. The improvement in the euro zone current account deficit largely comes on the back of lower imports in peripheral currencies because of lower incomes. This has led to slow growth and risk of deflation. In consequence European Central Bank (ECB) policy rates are negative and the ECB has an obsession with weakening the euro to prevent deflation.

By contrast, the structural improvement in the US current account deficit is an unambiguous US dollar positive. Apart from reduced funding needs, the support for US activity and the competitive improvement in some areas could attract portfolio and direct investment to the US, giving the US dollar an additional boost. The expected current account improvement versus a baseline 2.4% of GDP current account deficit is the equivalent of almost $1 billion per business day coming to the US, and that is material even in a deep foreign exchange (FX) market.

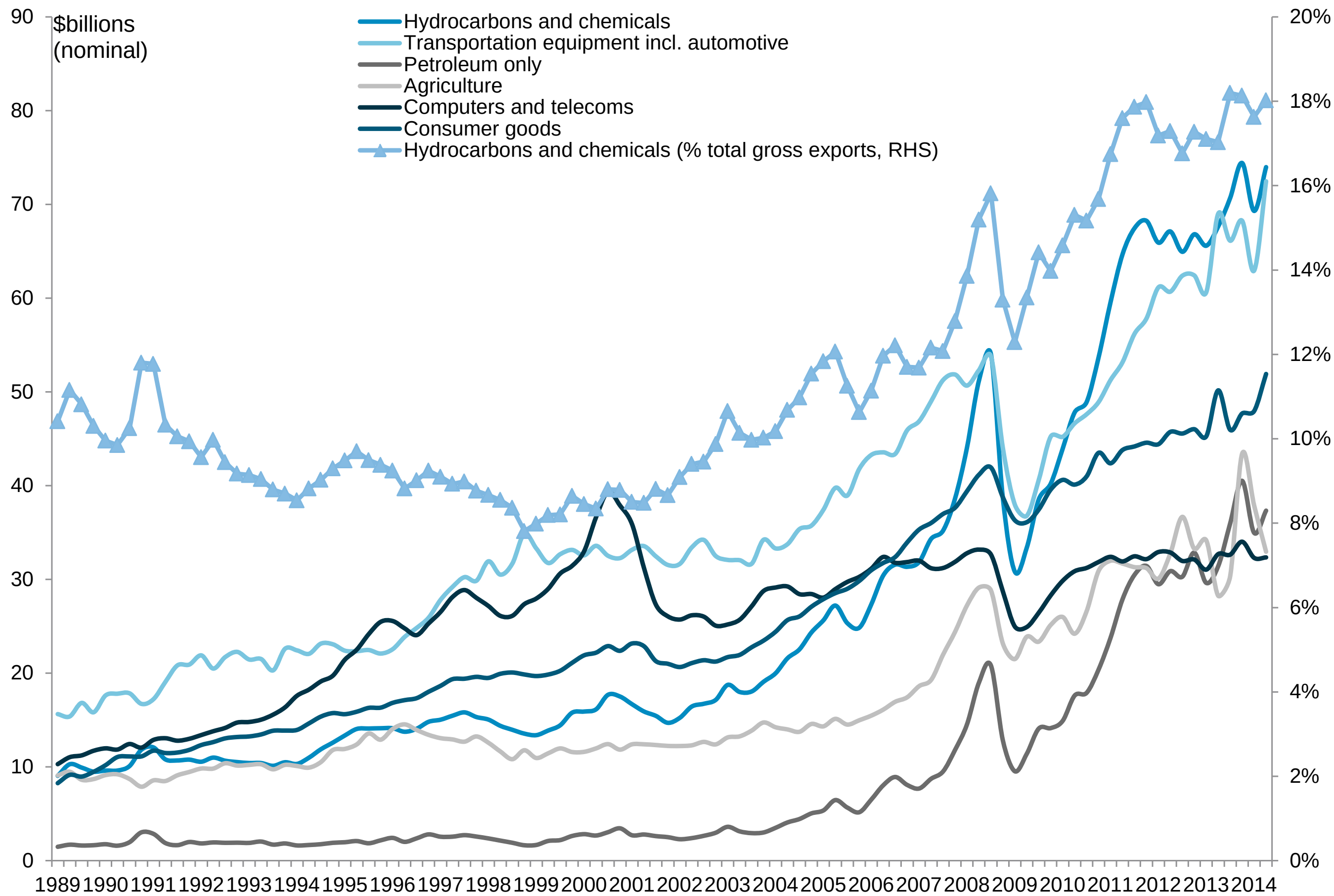
Expect incremental ad hoc liberalization of US crude oil exports

Edward L Morse
Global Head of Commodities Research

Crude oil, petroleum products, coal, NGLs and natural gas exports are increasingly dominating the US external sector. Even before the jump in US crude oil exports in 2014, sales abroad of hydrocarbons and petrochemicals reached the number one area of US export sales, catapulting in the past half-decade over agricultural goods, capital goods and transportation equipment (including combined aircraft and heavy duty farming and other trucking goods).

Whether or not crude oil exports are further liberalized in the years ahead, energy exports will increasingly dominate the external sector for the United States. Citi expects nearly 3-m b/d of combined petroleum product net exports and 1-m b/d of gross crude oil exports, if not by the end of 2014 certainly within the first two quarters of 2015, given the growing surplus of natural gas, natural gas liquids and petroleum products (no matter what the price of oil in the years ahead). Restrictions on exports of US crude oil will continue to make it profitable to build various levels of "refining" including via splitters and simple distillation units, both in independent refining operations and through expansions of existing refining facilities.

Figure 118. US gross exports of hydrocarbons and chemicals versus other top major categories of goods



Source: US Bureau of Economic Analysis, Citi Research

Two growing trends will continue to push hydrocarbon exports, even if crude oil wellhead prices average $20-25 less than they have over the past four years. These are, first, a growing quantity of Canadian oil production reaching waterborne price points on all three US coasts – the East and West Coast via rail and the Gulf Coast via rail and pipeline, even if Keystone XL is not licensed. As Canadian production reaches waterborne levels, the drive to export will likely be economic and could result in higher netback values for Canadian crude oil even of global prices fall. Second, as more and more light sweet crude oil is produced, more and more will be stranded, whether inland or at coastal areas, driving discounted pricing that incentivizes greater exports.

If the period ahead is to see lower oil prices, there will be increasing pressures, and an increased national interest, in allowing exports of larger volumes of condensate and even of light tight oil. Citi expects a two stage process in the absence of further liberalization of exports. One stage will come from the crowding of light crude oil on the US Gulf Coast, well before the end of 2015, with the export bottleneck causing the price spread between US crude oil prices (LLS or WTI on the US Gulf Coast) and Brent prices to widen to $10 or more. The other is the bottlenecking of inland crude oil, particularly in the Midland area of Teas and the US Gulf Coast, which can also see local prices widen in discount versus waterborne prices, given the lagging of infrastructure build-out between the Permian Basin and the Texas waterborne market.

Confronting a growing array of domestic pressures, Citi does not expect dramatic one-off moves by the US government to fully liberalize crude oil exports. Rather we expect incremental, ad hoc decision-making to point toward a significantly more liberalized future crude oil regulatory regime. Politics could well intervene however. Post mid-term elections in the United States, Citi expects initiatives in Congress to propose ending the legal obstacles to crude oil exports with changes in the law impeding exports of oil in federal waters or from federal lands, and via pipelines mandated through federal rights-of-way. A change in the laws won't happen overnight, but could be enacted before 2016.

Even without a change in the law, Citi perceives growing pressure being built on the US Administration to liberalized oil exports. Initial pressures will build on condensates, whose production growth along with the growth in ambiguity over what constitutes condensates should see pressure on government from both producers of condensate at the wellhead and users in refineries to define condensates in such a way as to maximize exports. A lower price environment makes such decisions even more compelling, since the rejection of condensates by refiners results in even further price repression and further inducements to curtail production growth, which should increasingly be seen as contrary to national interests.

As exports of crude oil to Canada soon reach a market size limitation, pressures will grow to develop exports elsewhere, starting with Mexico, as argued in this report. The good news for facilitating these exports is the existence of a legal and regulatory framework that make it impossible to stop such exports. If US exports of crude oil to Canada are naturally capped at around 500-k b/d because of the size of the Canadian market, exports to Mexico are capped at perhaps 300-k b/d. In this case, unlike Canada, it is guesswork to try to define the limits of market size. Eastern Canada has been importing some 600-k b/d from West Africa, the Mediterranean and NW Europe and has production offshore Eastern Canada that can receive a higher netback in crude-short Europe than in crude-short Eastern Canada. But in the case of Mexico, the country has never imported sizeable quantities from the US and estimating the market size requires an understanding of

how much the performance of Mexican refineries can be improved by importing light sweet crude oil from Texas and exporting more heavier crudes to the US, Europe and into the Pacific Basin (including into the US Pacific area, from Washington south through California).

Soon after that, pressures will continue to build to export to trading partners of the United States with whom there are free trade agreements in place. Among the nearly two dozen such countries, South Korea, Singapore, Chile and Israel stand out. Each of these countries' FTAs with the US have most favored nation clauses, which can be read as resulting in trade discrimination given the allowance of crude oil exports to Canada and potentially to Mexico. It is highly likely that within the next year each of them will be seeking to buy US crude oil, especially if, as Citi expects, exports to Mexico are to begin soon. It would be extremely difficult on an ad hoc basis to find ways to deny requests to export to these countries in light of what is unfolding vis-à-vis Mexico. Combined these markets are around 4.3-m b/d, representing perhaps as much as 1-m b/d of incremental sales from the US; Singapore, in particular, is home to 1.3-m b/d of refinery capacity.

US crude exports to Mexico would be initially in the form of crude exchanges, with US-produced light, sweet crudes exchanged for Mexican-produced heavy, sour crudes. It's conceivable that other exchanges with other countries could be in the works, which could help provide a further outlet for condensate/crude surpluses. But except for Venezuela, it is hard to find other situations where such a transaction would make sense for both sides. In the case of Mexico, there is a good fit between the heavy crude exported from Mexico to the US versus the light crude that could be sent back to Mexico in exchange; Mexican refineries would benefit from running the light sweet crude to improve light product yields, and US Gulf Coast refiners could continue to run its preferred crude slate of heavier, sourer oil. But other than Mexico, and in principle, Canada, there may not be many other cases where this would be widely taken up.

Politics can intrude and push for even further crude oil export liberalization. This is particularly true in the current geopolitical environment, which could well propel the negotiations of FTAs with both Asian trading partners and the European Union, via the TPP and TTIP. The Trans Pacific Partnership (TPP) and the Trans-Atlantic Trade and Investment Partnership (TTIP) are both expected to gain traction in the final two years of the Obama Administration. The TPP involves eleven countries, many of which already have FTAs with the US, including Australia, Brunei, Canada, Chile, Japan, Malaysia, Mexico, New Zealand, Peru, Singapore and Vietnam. Although smacking of a political agreement that excludes China, the FTA would potentially provide these countries greater access to US crude and other hydrocarbons. Similarly the TTIP, with the European Union has gain political make it possible for European customers of Russia to buy oil and gas potentially from the United States instead.

If the TPP and TTIP free trade arrangements were put in place with an oil element, they would go a long way to providing export outlets for US crude oil even in the absence of a full dismantling of the obstacles to US crude oil exports. If they were put in place it would probably not be a difficult next step to reverse the trade restrictions that were in any event put in place in a very different environment in the 1970s, when the US had a price control regime in place and where the bans on petroleum and petroleum product exports had to be implement to prevent scarcity in the United States.

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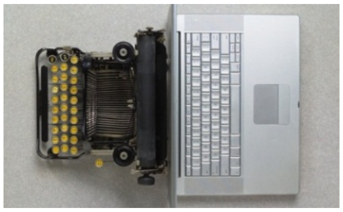

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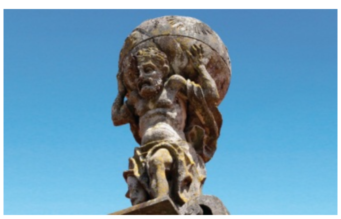

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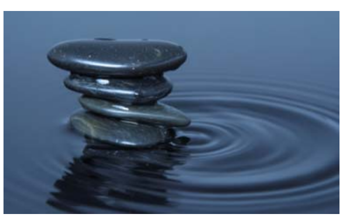

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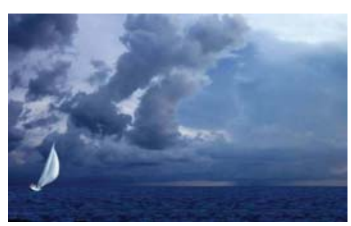

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Notes

Notes

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Key Insights regarding the future of US Energy

COMMODITIES

The US has been a net importer of oil since 1949 and dependence on foreign oil rose to nearly 50% in the mid-1980s. / In the past 8 years, the US has decreased its net oil imports by a stunning 8.7-m b/d and we expect the oil import gap will be totally closed well before the end of the decade, possibly by 2019 if not by 2018.

INFRASTRUCTURE

Beginning with the ramp-up of US production, there has been a lag in infrastructure to get new production to domestic markets and to get both product and crude to foreign markets, resulting in an enormous build-out in rail transportation to fill the gap. / Going forward, infrastructure build-out will come in three areas; infrastructure related to the shipments and exports of hydrocarbons; infrastructure related to the development of new oil/ gas fields; and infrastructure related to the industrial build-out or expansion of existing facilities.

POLICY

Since the 1970s, the US has banned the unlicensed export of crude oil, a policy put in place after the crippling Arab embargo that followed the 1973 Yom Kippur War. Confronting a growing array of domestic pressure, we expect incremental, ad hoc decision-making to point toward a significantly more liberalized future crude oil regulatory regime.