

Unlocking the economic potential of North America's energy resources

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Steve Strongin
1(212)357-4706
steve.strongin@gs.com
Goldman, Sachs & Co.

Jeff Currie
1(212)357-6801
jeffrey.currie@gs.com
Goldman, Sachs & Co.

Brian Singer
1(212)902-8259
brian.singer@gs.com
Goldman, Sachs & Co.

Michael Lapedes
1(212)357-6307
michael.lapedes@gs.com
Goldman, Sachs & Co.

Patrick Archambault
1(212)902-2817
patrick.archambault@gs.com
Goldman, Sachs & Co.

Daniel Quigley
+44(20)7774-3470
daniel.quigley@gs.com
Goldman Sachs International

Alberto Ramos
1(212)357-5768
alberto.ramos@gs.com
Goldman, Sachs & Co.

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Executive Summary

The “demand response” phase of the shale revolution is stalling

Last year North America spent nearly \$200 billion on producing oil and gas, attracting over 50% of global upstream investment, outspending Russia and Saudi Arabia combined by an astonishing factor of 10-to-1. However, as supply-side investment surges ahead, demand-side investment lags.

Although North America has access to some of the lowest energy prices in the world, reinvestment rates in energy-intensive manufacturing that create high-value jobs lag those of Asia and the Middle East, by a more impressive 15-to-1. Further, the region has also fallen short in building the infrastructure to ensure the benefits of abundant energy supplies can be fully reaped. As temperatures plunged this past winter, gas could not be delivered where it was needed, creating regional price spikes.

If these trends continue, North America will not only fail to harness the benefits from the shale revolution it created, but it will also forego over the next decade more than 2 million new jobs, 1.0 % of additional GDP growth and at least a 5% incremental reduction in greenhouse-gas emissions.

The window of opportunity for North America to benefit fully from its potential is limited. While North America can easily point to the economic advantages generated by shale, these advantages were based on legacy infrastructure rather than resource availability. Many other countries have similar resources as North America, particularly China. They only lack the infrastructure needed to unlock these resources. This means that it is only a question of time before other nations catch up with North America.

Time is of the essence to act now, so what can be done to turn this resource wealth into real economic value?

Opportunity to pursue shared environmental and economic goals

All of these problems share a common solution: stable and well-defined energy, environmental and transportation policies. While the “shale revolution” has taken place without an energy policy, we note that this involves short-term, quick-turnaround investments. In contrast, the demand-side investments that we need today are larger in scale, requiring decades to recoup the investment, and as such require a high level of confidence in future policies.

Creating policy aimed at establishing such long-term confidence has real economic benefits and is an opportunity for business and government to work together to support the shared goal of a clean environment, a strong economy and sustainable job creation that has historically defined North America.

We therefore see three key policy themes on which business and government can work together to create the conditions necessary for this much-needed investment: (1) reducing uncertainty through effective regulations, (2) optimizing costs and emissions across the entire value chain and (3) focusing on scalability and diversification of technologies.

1. Reduce uncertainty through durable and effective regulations

The long-term nature of energy-intensive demand-side investments underscores the need for stable, not temporary, rules that create an economic vision of the future. To make multi-billion dollar demand-side investments that require decades to generate an adequate rate

of return, investors need to be confident in the future for fracking in that it can be done safely within well-defined and well-understood rules.

In order to be predictable, regulation needs to be clear, uniform and effective. In our view, effective energy policy should be conducted in terms of both protecting the environment and in attracting longer-term responsible investment. These objectives are not mutually exclusive.

2. Optimize costs and emissions along the value chain

To optimize emissions and costs, emission limits should be approached from the perspective of “well-to-wheel” rather than simply focusing on certain downstream segments such as automobiles or power generation. For instance, unless the energy source meaningfully shifts to renewable energy, the headline emissions benefits of a “zero-emissions” auto industry are overstated when accounting for the entire well-to-wheel supply chain. We estimate that if methane emissions at the well-head and pipeline were contained, gas-based fuels could deliver transportation with lower total emissions than gasoline at lower investment costs than the “zero-emissions” automotive technologies, and these trade-offs therefore need to be carefully addressed.

Specifically, we believe that natural gas-based ethanol and electric vehicles are the two most promising alternatives to gasoline based upon cost, potential emission reductions and consumer payback. However, natural gas-based ethanol and electric vehicles have very divergent investment requirements: ethanol is very front-end-loaded at the upstream drilling and refining stage with little burden on the consumer, whereas electric vehicles require comparatively less infrastructure investment but a much larger investment borne by the consumer, and a high level of uncertainty remains around battery costs.

3. Focus on scalability and diversification of technologies

Renewable energy is cleaner and more sustainable, but currently there are real challenges, such as intermittency (the sun is not always shining, nor the wind blowing), that currently limit their ability to reliably supply North America’s power needs. Through improving cost structures and technologies, as well as various incentives and mandates, renewables are set to continue to take market share. However, until centralized electricity storage technology options emerge and become scalable, technologically driven limits on scalability exist for renewables – making other technology options necessary as base-load resources.

Cost and environmental concerns may drive a lower reliance on nuclear or coal generation, impacting their scalability, making increasing use of natural gas a necessity as more of a base-load resource, especially given significant scalability advantages. While policy should help facilitate R&D in new technologies, it should also ensure that it does not crowd out investment of known scalable technologies, which have the potential to lower emissions. But predicting technological advances remains challenging, which is why we recommend a diversified portfolio approach to power generation with an emphasis on natural gas until a new clean, low-cost, scalable technology emerges.

Five questions that need answers to kick-start the demand phase of the revolution

We believe that to create an environment more conducive to investment to achieve these goals, five questions need to be addressed before kick-starting the demand response phase of the shale revolution: (1) What are the best fracking practices and water rules? (2) How can pipeline rules and regulations be improved? (3) What are optimal strategies for capturing fugitive methane? (4) How can natural gas-based ethanol (E85) fueled and electric vehicles be encouraged in the transportation sector? and (5) What reforms in the power generation sector should be instituted?

Overview: Unlocking the economic potential of North America’s energy resources

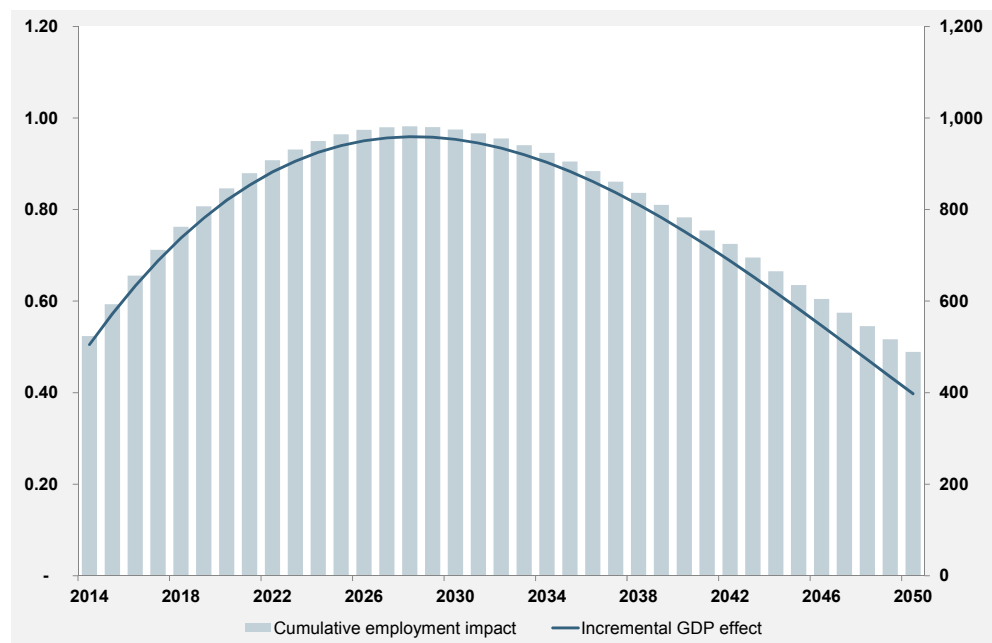
In policy circles, investment forums and public commentaries today, it has become an almost common refrain to cite the energy revolution that is occurring in the United States and, more broadly, in North America. The economic potential from this revolution is, no doubt, tremendous and has major implications for the US and global economies. But, the United States will never fully realize the benefits from the energy opportunity and create the new jobs needed if it does not have a demonstrable and coherent energy and environmental policy that creates the right conditions for a longer-term approach to investment and infrastructure.

The economic benefits of getting shale right could be considerable

Under a favorable policy mix we estimate that shale technology has the potential to boost North American economic activity, create jobs and reduce emissions considerably over the next decade. We estimate that aggressive policy reform has the potential to increase economic growth by 0.9 percentage points per year in the United States and create 1 million jobs over the next decade. Similarly, we see the opportunity for Mexican GDP growth to benefit by 1 to 1.5 percentage points per year over the next decade, creating more than 1 million jobs. And we estimate Canadian growth could be boosted by 0.25% per year over the same time horizon. At the same time, the shift towards cleaner burning fuels in both power generation and transportation combined with methane capture has the potential to reduce emissions in the United States alone by at least 5% by 2025.

Exhibit 1: The economic potential from investing in gas demand is considerable

GS estimated incremental GDP (in percentage point, lhs) and cumulative employment impact (thous, rhs) in “max. potential” gas demand scenario

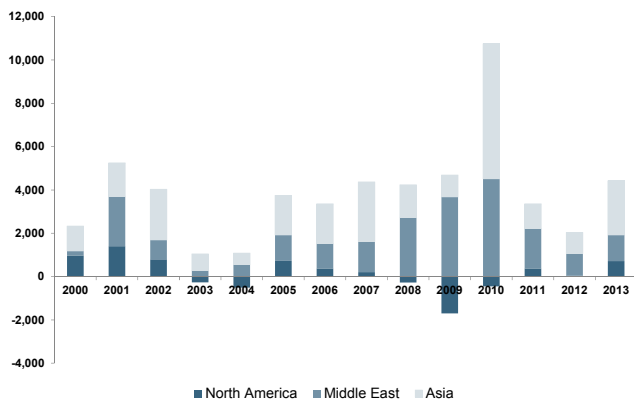


Source: Goldman Sachs Global Investment Research.

The “demand response” phase of the shale revolution is stalling

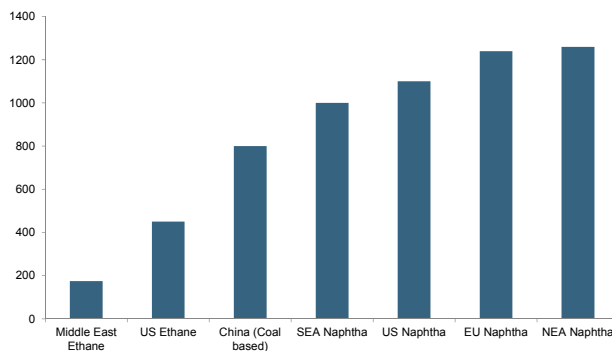
But the future of shale will ultimately depend on how energy and environmental policy can adapt to the changing technology. To date, most analysis has focused on the positives for North America of the shale revolution. On the other hand, far less attention has been paid to the economic opportunities North America has failed to harness from the revolution. Instead, the United States seems more on track to export shale, as the United States has lagged other countries in generating the demand – and the high-value manufacturing jobs that come along with this demand – needed to consume shale gas. In this respect, we believe that the shale revolution may stall and not see the full longevity of the “demand response” phase.

Exhibit 2: US ethylene additions have been consistently lower than both the Middle East and Asia...
Ethylene capacity additions, in thousand tonnes



Source: IHS.

Exhibit 3: ... despite its favorable position on the cost curve, especially relative to Asia
Ethylene breakeven costs by region/feedstock (2013), in US \$/tonne



Source: IHS.

The United States and North America more broadly have access to some of the lowest natural gas prices in the world. But reinvestment rates in the energy-intensive manufacturing that create high-value jobs lag those of Asia and the Middle East. For example, both of these regions have outspent the United States by a remarkable 15-to-1 on new ethylene expansions over the last four years (see Exhibits 2 and 3). Despite the fact that US natural gas can be transformed into motor fuels for as little as \$1.60 per gallon equivalent – and with lower well-to-wheel emissions than gasoline – very little investment has gone towards creating gas-based transportation demand in the United States.

Exhibit 4: US investment in upstream energy has been strong relative to peers
Global energy production in volume and value, and capex (2013)

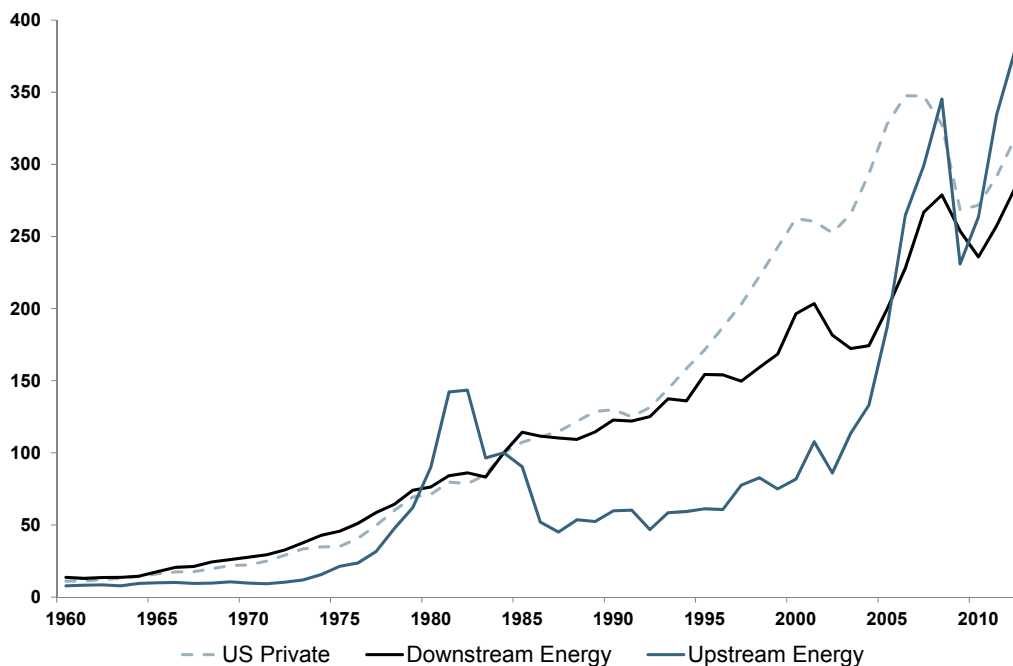
Country	Total Liquids (kb/d)	Natural Gas (bcf)	Thermal Coal (mln mt)	Market Value* (Bn. US\$)	Drilling Capex (Bn. US\$)
US	11,722	24,326	823	\$825	\$152
Russia	10,877	23,580	199	\$730	\$12
Saudi Arabia	11,306	3,860	0	\$495	\$9
China	4,212	4,268	3,054	\$476	\$50
Canada	4,008	5,493	26	\$227	\$23

*Using Brent price for Liquids, Europe price for Natural gas and Australia price for coal

Source: BP statistical review, Spears & Associates, China Ministry of Land and Resources, Haver Analytics, Goldman Sachs Global Investment Research.

As demand lags, supply is surging ahead. Last year the United States spent \$152 billion on producing oil and gas, attracting nearly 50% of global investment, and outspent Russia by an equal factor of 15-to-1 (see Exhibit 4). Demand simply cannot keep pace with supply – and this is why exports are the focus of policy choices today. To keep the value of shale at home, and to reap its economic benefits here rather than abroad, significant investment is needed on the demand side (see Exhibit 5).

Exhibit 5: While upstream energy investment is now outperforming US average, the downstream sector continues its long-term underperformance
Capital investment index, 1984=100



Source: Haver Analytics, Goldman Sachs Global Investment Research.

Uncertainty lies behind this failure to harness the shale revolution

Several factors underlie disappointing demand-side investment. These include a lack of confidence in the future economics of these projects, a lengthy and uncertain permitting process, regulations that cannot keep pace with today's technologies and substantial uncertainty around the long-term viability of shale gas. All of these problems share a common solution: stable and well-defined environmental, energy and transportation policies. It is true that the "shale revolution" has taken place without a matching energy policy, but shale has been a relatively quick-turnaround investment. In contrast, the demand-side investments needed today are larger in scale, requiring decades to recoup the investment and a high level of confidence in future policies.

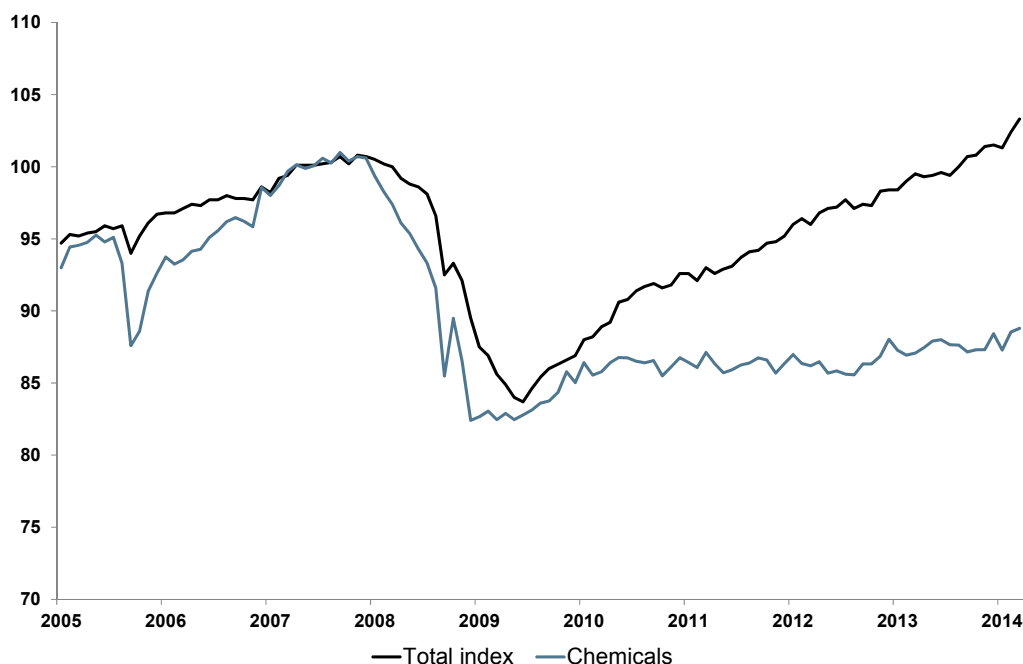
Although there exists substantial economic potential in creating demand for energy from the transportation, industrial and residential sectors, very little has been done today to harness this potential. Heating costs this winter showed how the United States has fallen short in reaping the benefits of the abundant gas it has already produced. As temperatures plunged, gas could not be delivered where it was needed. The result was natural gas prices in large metro regions in the northeast above \$120/mmBtu, even as prices stood at just \$4/mmBtu elsewhere across much of the United States. Insufficient investment in pipeline and distribution infrastructure lay behind this severe dislocation in prices.

Even though natural gas prices in the United States are 60% to 75% lower than in Asia and Europe, energy-intensive manufacturing has failed to rise significantly or to create much-needed jobs. Since the onset of the shale revolution in late 2010, key energy-intensive manufacturing sectors such as chemicals and petroleum products have underperformed the broader economy by 2.2% p.a. and have generated only 5,000 new jobs, compared to 40,000 jobs if these industries had grown in line with US manufacturing more generally (see Exhibit 6).

Today’s policies do not embrace the new fuel options generated from new technologies; they constrain the use of methanol and natural gas-based ethanol made from natural gas in the fuel stream, despite lower costs and potentially lower emissions. At the same time, long-term investment decisions—which are for our long-term economic benefit—require a higher degree of clarity on our national LNG and oil export posture. This would reduce uncertainty around future pricing and availability of cheap energy.

Exhibit 6: While headline IP has recovered post-crisis, energy-intensive sectors have not performed so well

Industrial Production Index, seasonally adjusted (2007 = 100)



Source: Haver Analytics.

Moreover, the inability to use abundant shale resources is beginning to derail the shale revolution on the supply side as well, which has been a bright spot for the US economy. The shale revolution created an estimated 175,000 new jobs in oil and gas extraction and services and boosted industrial production growth by one-third since 2010. In fact, today natural gas production is already completely constrained by a lack of demand. This can be seen in the substantial slowdown in natural gas production growth rates after 2011 (see Exhibit 7).

Exhibit 7: Supply growth has recently been weighed down by demand constraints
 US dry gas production 12 month moving average, in Bcf/d



Source: EIA

Policy can address these issues to unlock the potential

As we laid out above, the opportunity for the North American economy to profit from increased capacity to consume the shale resources it is producing is considerable. To take advantage of this opportunity, policy needs to solidify confidence in the next 30 years that is required to attract the capital. The key in unlocking the potential on the demand side is to attract the capital. For example, if we were to invest \$1.2 trillion dollars today in gas-based automotive technologies the United States could consistently reduce its energy bills by as much as 10% by 2035.

However, the reality of the shale revolution is that there is ample supply potential of hydrocarbon fuels that is economic at current prices. As a result, **running out of hydrocarbon fuels is not going to force the economics of renewables, creating an even more difficult task ahead in reducing emissions.** This further increases the need for well thought out environmental and energy policy.

Further, the window for North America to benefit fully from its potential is limited. While North America can easily point to the economic advantages generated by shale, these advantages were based on legacy infrastructure rather than resource availability. Many other countries have similar resources as North America, particularly China. They only lack the infrastructure needed to unlock these resources. This means that it is only a question of time before other nations catch up with North America and it could be a matter of years rather than decades.

All of these factors underscore the need for timely cooperation among business leaders, investors and policymakers. Indeed, in the next section (pages 25-29), **we describe the key policy questions we think need to be addressed in the near term to kick-start a sustained demand response phase of the shale revolution** : (1) What are the best fracking practices and water rules? (2) How can pipeline rules and regulations be improved? (3) What are optimal strategies for capturing fugitive methane? (4) How can

natural gas-based ethanol (E85) fueled and electric vehicles be encouraged in the transportation sector? and (5) What reforms in the power generation sector should be instituted?

These are the “low hanging fruit” that we believe could set policy on the path to encouraging long term confidence in the ability of the energy sector to deliver its potential across North America.

We then go on to investigate in detail three key policy themes we believe should remain in focus in the longer term where business and government can work together to unlock the full potential of shale: (1) reducing future uncertainty around resource availability, (2) optimizing costs and emissions across the entire supply chain and (3) focusing on scalability of technologies in both transportation and power generation. In so doing, we offer a vision for how such policy reforms could shape the outlook for transportation, industrial and power generation sectors.

Finally, from page 57, we estimate the economic benefits that could be gained from this policy environment in two separate case studies, for the United States and Mexico respectively.

On page 74, we include a Glossary which defines the terms we use throughout the paper.

For the remainder of this overview, we now explain why we believe these three themes are of core importance to conducting effective energy policy in North America and how addressing them can generate a significant economic boost to the North American economy.

1. Policy should aim to reduce uncertainty and create stability and credibility

To create an economic vision of the future, an effective environmental and energy policy needs to be defined strictly enough by addressing all the 5 key questions that we outline in the policy question section such that future government changes do not lead to future policy change, including interpretation of enforcement.

Since the onset of the shale revolution, the North American energy market has failed to fully capture the economic benefits of shale. This is most apparent in the energy-intensive manufacturing sectors, where industrial output has notably underperformed the broader manufacturing recovery (recall Exhibit 6).

Driving this underperformance has been a lack of investment in large-scale, capital-intensive projects required to transform energy into growth, including the failure to invest in the pipeline and distribution mechanisms needed for the energy to reach its consumers. As we noted earlier, uncertainty driven delays have underpinned these failures. We believe the following issues in the market have contributed to the high level of uncertainty at the energy demand level:

1. **Little confidence in the future price and availability of energy supplies**, as many consumers are left with the painful memories of the 1990s when large-scale investments were made only to have the viability completely lost during the early 2000s when North American energy prices spiked from the lowest in the world to the highest in the world almost overnight, as the excess capacity driven by 1970s energy policy was completely exhausted.
2. **This lack of confidence is further exacerbated by the lack of policy addressing key environmental and energy issues.** The long-term, large-scale nature of these demand-side investments requires rules and regulations that create an economic and environmental vision of the future. This means that investors must be reassured that

fracking can be done safely within well-defined and well-understood rules, and that any labor shortages can be managed in the context of well-articulated immigration policies, such that they believe they can recoup their investment over a long time horizon. Further, a recognition that a renewables-focused generation mix will likely require natural gas as an inexpensive complement to solve the intermittency problem will be key.

The key is that policy needs to establish confidence in the sustainability of an environmentally safe energy supply with confidence around its pricing, the availability of labor and timely and efficient permitting that is matched to current technologies. Once the uncertainty is diminished investors would likely be far more willing to commit capital to long-term demand-side projects.

How uncertainty delays investment

Companies weigh two important issues when undertaking a large-scale investment:

1. **Large-scale capital investments are mostly irreversible** such that the company cannot disinvest, making the investment a sunk cost, which also applies to labor due to the costs associated with hiring, training and firing.
2. **An investment decision can be delayed**, which allows the company to gather new information about input prices such as natural gas, the future regulatory environment and other market conditions like the demand for the product they are considering producing.

Most importantly, the investment behavior driven by these two characteristics is easily shown to be extremely sensitive to the risks and uncertainty around factors such as energy input prices or supply availability (see the textbox on Investment Delays Stemming from Uncertainty). For example, in making the decision to build an energy-intensive manufacturing plant, the risks around long-term natural gas prices, future supply availability ten years from now and the regulatory landscape are far more important to the investment decision than the consensus view of \$4.25/mmBtu for long-term natural gas prices.

The result is that the risks around these variables - from energy prices and supply availability to interest rates and policy – rather than the actual values of these variables create the investment problem. **The implications of this are far-reaching for policymakers, suggesting that they should be focused on demonstrating stability and credibility in trying to stimulate investment**, as this is more important than simple tax breaks or other incentives that can change over time with governments.

The empirical evidence of delayed investment

Not only can we establish theoretically how uncertainty creates delays in investment, but the empirical evidence in the energy-intensive manufacturing sectors also bares out this conclusion. Despite extremely attractive economics, a large number of projects are still currently being delayed, pushed out in time for a variety of reasons, including permitting, land siting, labor availability, future gas prices and supply availability (see Exhibits 8-9).

Exhibit 8: Despite favorable economics, many projects are still being delayed...

Examples of delays to investment projects in the US chemicals industry

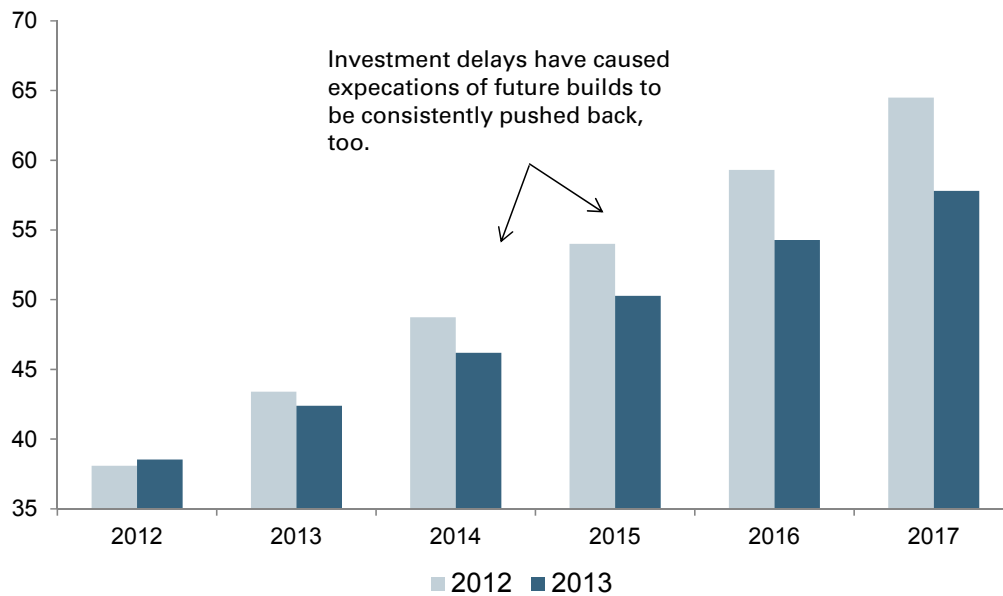
Owner	Location	Product	Capacity Addition (kmt/year)	Targeted Start Up Date	
				Old	New
Agrium	Midwest	Nitrogen	1000	-	Indefinite Hold
Agrebon	Casselton, ND	Nitrogen	7	2014	2015
BioNitrogen	Hardee, FL	Nitrogen	72	2014	2015
US Nitrogen (Austin Powder)	Greenville, TN	Nitrogen	73	2014	2015
Celanese	Houston, TX	Methanol	1,300	2Q2015	4Q2015
Enterprise	Houston, TX	PDH	750	3Q2015	1Q2016
LSB Industries	El Dorado, AR	Nitrogen	375	2015	2016
Valero	New Orleans, LA	Methanol	1,600	1Q2016	2018
Chevron-Phillips	Houston, TX	Ethylene	1,500	2016	2017
Exxon	Houston, TX	Ethylene	1,500	2016	2017
CHS Inc	Spiritwood, ND	Nitrogen	803	2016	2017
Texas Clean Energy Project	Penwall, TX	Nitrogen	484	2016	2017
Ohio Valley Resources	Rockport, IN	Nitrogen	883	2016	2017
Yara	Belle Plaine, SK	Nitrogen	750	2016	Indefinite Hold
Hydrogen Energy California (HECA, 9CS Energy)	Kern County, CA	Nitrogen	400	2017	2018
CHS Inc	Spiritwood, ND	Nitrogen	803	2017	2019
Shell	Pittsburgh, PA	Ethylene	1,000	2017	On Hold
Idemitsu Kosan	Freeport, TX	Alpha-Olefins	330	2017	Cancelled

Source: Company reports, Goldman Sachs Global Investment Research

Until energy consumers become more confident in the cost, access to supplies, policy, infrastructure development and technology of future end-use (electric cars, hydrogen fuel cells, CNG, etc.), they will be hesitant to invest and the market will need to continue to price in a higher level of uncertainty. This uncertainty, whether manifested in high and volatile regional spreads like this past winter or more importantly in the oil-to-gas spread, can be viewed as the price of an option for better project terms in the future, which is ultimately incorporated into today's investment decision.

Exhibit 9: ...and expectations for US chemicals investment have been pushing back, too

Forecast capital expenditure in the US chemicals industry by forecast year

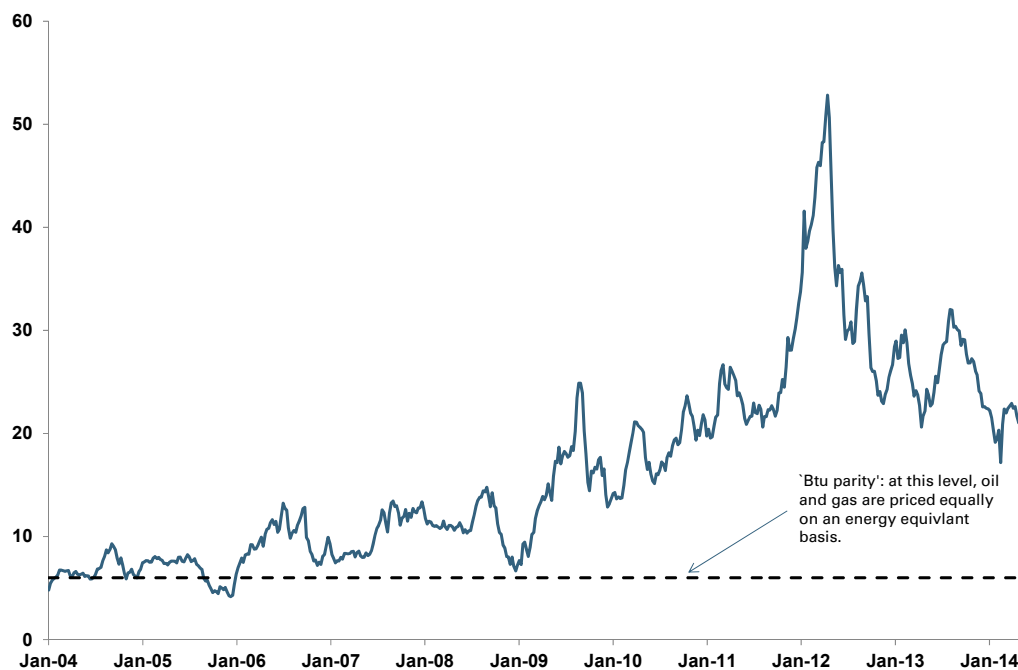


Source: American Chemistry Council

If we use the oil-to-gas spread as a measure of the value of the option to invest in gas-fired manufacturing or generation capacity, then the value of this option rises with the level of uncertainty around making such investments. This option had no value in 2007 when gas was trading near parity with oil but it increased as the shale revolution took hold, creating new investment options, but it has continued to rise as the investment environment has remained difficult, going far past what would be considered optimal (see Exhibit 10).

Exhibit 10: The lack of demand response has come despite gas pricing cheaply relative to oil after 2007

Cost of WTI oil relative to NYMEX natural gas front-month contracts, weekly average in mmBtu/bbl



Source: ICE, NYMEX, Goldman Sachs Global Investment Research

The key issue here is that the supply-side investments do not suffer from these same investment uncertainty issues because they are far more quick-turnaround investments – shale energy is now a 12-month turnaround investment. In contrast, the demand-side investments require far longer to recoup the capital outlay, which is why it is critical for policy makers to create rules that are viewed both credibly and with confidence that they will not change such that the investor becomes confident that they will recoup their investment. This will likely require strict environmental regulations around fracking and fugitive methane emissions that are unlikely to be reversed in the future by a new government.

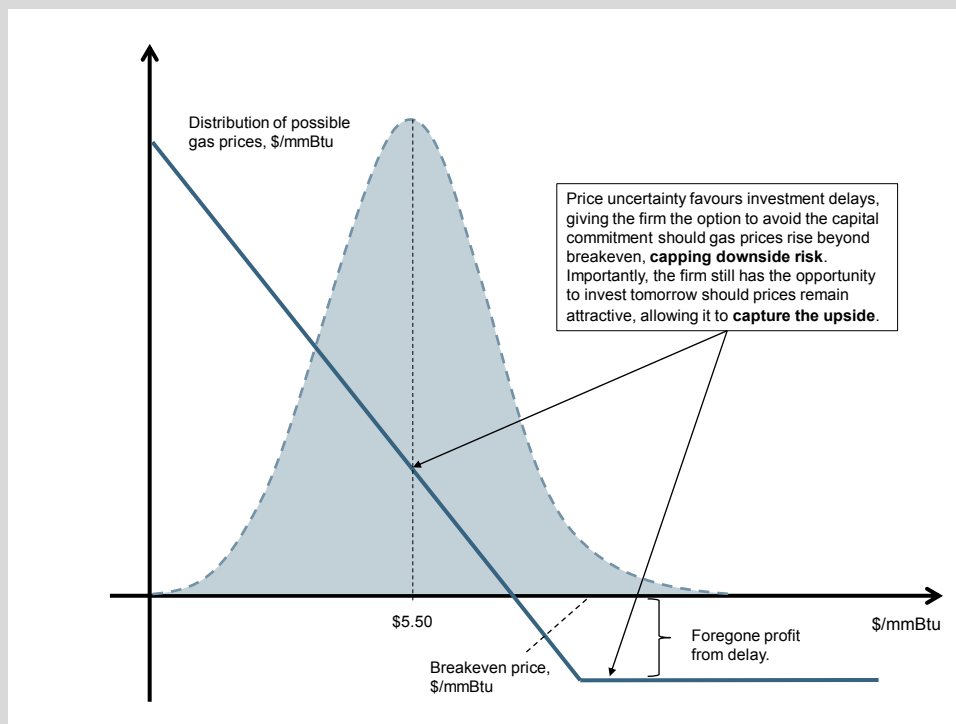
Box 1: Investment delays stemming from uncertainty

We outline a simplified analysis showing how uncertainty over supply availability, characterized by fears of price volatility, can delay the firm’s investment decision, even if a favorable, low-input cost environment is eventually reached. We apply this analysis to the case of US natural gas and a fertilizer company that is considering investing in a new factory. One of the key decisions the company must make is whether to invest today, while the regulatory environment and future of shale is still uncertain, or to delay their investment and wait for greater certainty over supply and prices of natural gas inputs.

Using the standard investment analysis technique of expected Net Present Value (NPV) we can demonstrate how the expected profitability of the decision to invest today is lower than that of waiting a year and investing when price certainty is greater. We make a number of simplifying assumptions in the outline analysis below, including a fixed price of fertilizer output and a constant 10% discount rate. But these do not change the overall market conclusion: greater input-price uncertainty is likely to lead to lower production volumes (at least in the short run), and higher prevailing final product prices.

Exhibit A: A simple example of how input price uncertainty can delay a firm’s fixed investment decision

Payoffs from delayed investment decision versus price uncertainty – assumes a continuous price distribution



Source: Goldman Sachs Global Investment Research

As a stylized example with a binary price distribution, we assume that the price of US natural gas could take two paths:

- The first path would see gas prices declining to \$4.00/mmBtu as shale technology continues to roll out and improve.
- The second path sees prices rising to \$7.00/mmBtu with shale technology being scaled back.

Assuming a long-term average price of \$5.50/mmBtu, we assign a probability of 50% to each outcome so that on average, gas prices are not expected to trend up or down.

Cont'd Box 1: Investment Delays Stemming from Uncertainty

The expected NPV of investing today is:

50% of the NPV under a gas price increase + 50% of the NPV under a gas price decrease

The fixed cost of the investment is \$1 billion. Operating profits are \$250m per year in the low-cost environment and \$50m per year in the high-cost environment.

This gives an expected NPV of \$500m for investing today:

Expected NPV from investing today = 50% Low-cost NPV + 50% High-cost NPV

$$\mathbf{\$500m = 0.5*(-1000+2500) + 0.5*(-1000+500)}$$

Under the same assumptions, if the fertilizer company delays investment until there is certainty over input prices then the expected NPV will either become more positive (if gas prices fall) or fall below zero (if gas prices rise).

Because no company would invest in a project with a negative NPV, the expected NPV from waiting becomes:

Expected NPV from waiting = (50% probability of prices falling * Low-cost NPV + 50% probability of prices rising * 0) * discount factor due to 1 year's delay

$$\mathbf{\$682m = 0.5*(-909 + 2273)}$$

The expected NPV is just over \$180m larger in the future, so the firm will rationally delay its investment decision. In fact, the firm would actually be willing to pay up to \$180m in order to secure this delay.

Increasing the range of prices, or the probability that we will end up in the high cost environment, increases the value of waiting, all else equal.

Box 2: Lift the uncertainty on the export ban rather than the ban itself

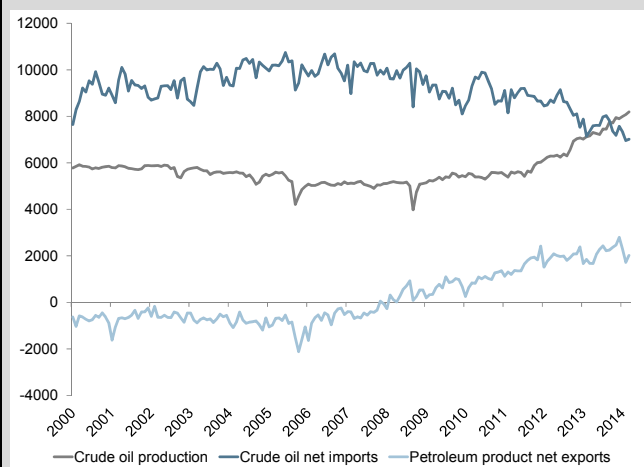
Although (for statutory reasons) the United States cannot export crude oil, surging domestic production has contributed to stabilize global oil prices through weaker US crude imports and higher petroleum product exports. Specifically, with US and global petroleum inventories stable over the past four years, the growth in US crude production has been sufficiently large to meet global oil demand growth despite weak supply growth outside North America. Further, the surge in shale oil production has likely also lowered the marginal cost of producing oil – and oil prices as a result – given the compelling economics of this growing source of future production growth.

Nevertheless, the current discount of US crude oil prices relative to seaborne crude oil prices has not translated into discounted domestic transportation fuel prices relative to the rest of the world because the United States continues to import petroleum products. As a result, the benefits of the US shale revolution through lower transportation fuel prices have been similar in the United States and abroad (absent currency and policy fluctuations as well as level of taxation). The idiosyncratic benefits of the US shale revolution on the US economy have so far been concentrated in specific sectors of the economy such as the refining sectors.

A clear commitment to keeping the export ban in place would stimulate downstream refinery capex investment to catch up to the upstream investment, helping to absorb growing domestic light crude production. On the other hand, if the export ban was lifted, US crude oil production would realize its strongest growth potential. However, with domestic prices converging back to seaborne crude oil prices, the margin advantage of domestic refiners would diminish and limit capex growth in the downstream sector. While export volumes would increase, the United States would be exporting the “value added” of processing its shale oil along with these barrels.

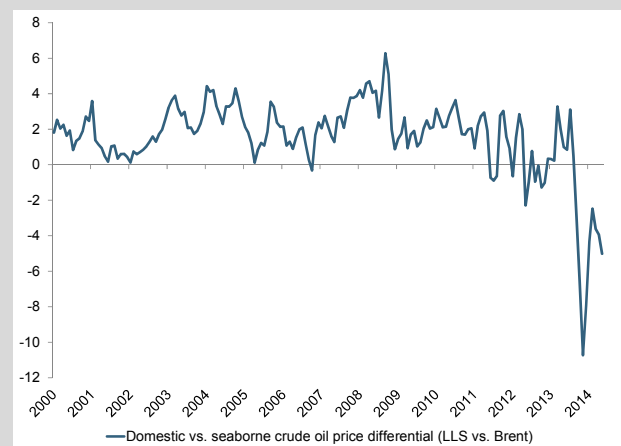
However, uncertainty on whether the export ban will be lifted or not (the current status quo) means that both upstream and downstream capex will ultimately suffer. Uncertainty is currently delaying any significant investment to open new refineries to process domestically produced crude, while simultaneously depressing demand and prices for upstream producers. This sub-optimal outcome features not only slowing domestic crude oil production but also limited growth in the downstream processing capacity and ultimately offers the least benefit to the US economy.

Exhibit 11: Surging domestic crude production has reduced the call of the US on the global oil market...
 Thousand Barrels per Day



Source: EIA.

Exhibit 12: ... however US transportation fuels have remained indexed to global prices despite declining domestic oil prices
 \$/bbl



Source: EIA.

2. Policy should optimize across the vertical supply chain from “well-to-wheel”

1. *North America light vehicle transport landscape is an open field at historical crossroads. We believe government policy as well as improvements in technical capability will have a significant impact in determining the mix of powertrains over the next few years;*
2. *We believe that natural gas-based ethanol and electric vehicles are the two most promising alternatives to gasoline based upon cost, potential emission reductions, consumer payback, and abundance of natural resources;*
3. *However, electric vehicles and natural gas based ethanol have very divergent investment requirements: ethanol is very front end loaded at the upstream drilling and refining stage with little burden on the consumer whereas electric vehicles require comparatively less infrastructure investment but a much larger investment borne by the consumer.*

Part of resolving the demand-related uncertainty is to create confidence in what are best and most efficient technologies and processes that reduce costs and emissions across the entire supply chain. Emission limits should be approached from the perspective of “well-to-wheel” rather than simply focusing on certain segments such as automobiles, power generation or refining. This requires a focus on all aspects of the supply chain where the total costs should be compared to the total emissions in evaluating competing technologies.

Exhibit 13: Ethanol well to wheel CO₂e emissions are similar to gasoline but could be materially improved by reducing methane leakage....

Grams of Co₂e per km

		CO ₂ e grams per kilometer						
		Gasoline	Diesel	Ethanol	Methanol	Compressed Natural Gas	Hydrogen fuel cell	Electric Vehicle
Well	Extraction	9	9	24	24	48	22	13
	Refining/conversion/ generation	51	39	60	60	13	158	155
	Transportation/pipeline	NA	NA	NA	NA	NA	NA	NA
	Retail distribution	NA	NA	NA	NA	NA	NA	NA
Wheels	Consumption	230	191	211	205	189	0	0
TOTAL		289	240	295	289	250	180	168
TOTAL adjusted for 3/4 reduction in CH ₄ leakage		289	240	266	260	233	180	168

Source: Argonne National Laboratory, Goldman Sachs Global Investment Research.

For example, the headline emissions benefits of a “zero-emissions” auto industry are overstated when accounting for emissions through the well-to-wheel supply chain. We estimate that if methane emissions at the well-head and pipeline were contained, gas-based fuels could deliver transportation with lower total emissions than gasoline with

lower investment requirements than the “zero-emissions” automotive technologies, and these trade-offs therefore need to be carefully addressed (see Exhibits 13 and 14).

Exhibit 14: ... at much lower all-in investment cost than the zero-emissions automotive technologies

Full lifecycle investment requirement for converting all 250mn light vehicles to various fuels, \$bn

		Incremental investment (billions)						
		Gasoline	Diesel	Ethanol	Methanol	Compressed Natural Gas	Hydrogen fuel cell	Electric Vehicle
Well ↓	Extraction	NA	\$ -	\$ 829	\$ 829	\$ 452	\$ 225	\$ 80
	Refining/conversion/generation	NA	\$ 363	\$ 1,281	\$ 768	\$ -	\$ 163	\$ 718
	Transportation/pipeline	NA	\$ -	\$ 19	\$ 19	\$ 209	\$ 139	\$ 425
	Retail distribution	NA	\$ 3	\$ 91	\$ 167	\$ 531	\$ 361	\$ 110
Wheels	Consumption	NA	\$ 457	\$ 76	\$ 127	\$ 2,029	\$ 5,072	\$ 2,110
TOTAL		NA	\$ 823	\$ 2,296	\$ 1,910	\$ 3,221	\$ 5,961	\$ 3,443

Source: Goldman Sachs Global Investment Research, company reports, EIA, NREI.

We believe the economic advantages of approaching environmental and energy policy questions from the perspective of the entire supply chain are significant and can achieve the following three benefits:

1. **Cost and emissions control.** Focusing on the entire vertical supply chain substantially increases the ability to control both costs and emissions throughout the distributions system by eliminating redundant, less-efficient and more-emitting steps, but most importantly, it allows for optimal utilization of the natural resource and renewable assets to avoid waste and reduce transportation costs.
2. **Reduce volatility in prices and supply.** Putting an emphasis on investments that optimize the vertical supply chain also allows for greater resource input access and optionality as opposed to simply being tied to one fuel type and or technology such as multi-fuel fired generation capacity, which allows the industry to adapt more quickly to changing market environments on both the supply and demand side.
3. **Avoid irreversible investments.** Energy technologies and infrastructure are extremely capital intensive with very long lead times to implement; therefore, any investment that turns out to not be of best use in the entire supply chain is extremely difficult to fix and likely irreversible, particularly given the scale of transportation, making a mistake is extremely costly.

From well-to-wheel or well-to-wall – many areas for improvement

Assessing and optimizing across the vertical supply chain clearly needs to begin with the **well or mine**, including exploration where emissions are first released. It is important to emphasize that these emissions, particularly methane, have real economic value if they can safely be contained and marketed. This further reduces not only the emissions, but the cost of the exploration and production of oil and gas. The Environmental Defense Group recently estimated that the value of capturing these emissions is \$110-\$150 million dollars.

Transportation of oil and gas to processing facilities is another area where both costs and emissions can be reduced. In gas the big issue is methane emissions. Here the problem is related to the lack of defined property rights for the pipeline operators such that they have no incentive to fix the leaks because they cannot take ownership of the gas they prevent from escaping and therefore cannot monetize it to pay for the leaks; this is a result of current federal policy.

In oil transportation, it is the difficult and lengthy process of getting pipelines approved and built that is forcing oil to be transported via railroads. This is not only a more expensive long-term transportation option, but it is also far more environmentally dangerous as evidenced by recent accidents and associated spills. Clearly, pipelines are far more optimal from both cost and environmental perspectives.

Processing is an area in which loss rates, emissions and costs can all be optimized. Natural gas has a clear competitive edge on a cost basis to nearly all other technologies. Not only are combined-cycle units far less costly than other technologies with relatively low emissions, but they also retain a high level of optionality in that alternative fuels can be processed to generate electricity in time of duress. Even on the transportation side – conversion to methanol, natural gas-based ethanol and compressed natural gas are all relatively low cost processing technologies on a capital cost basis.

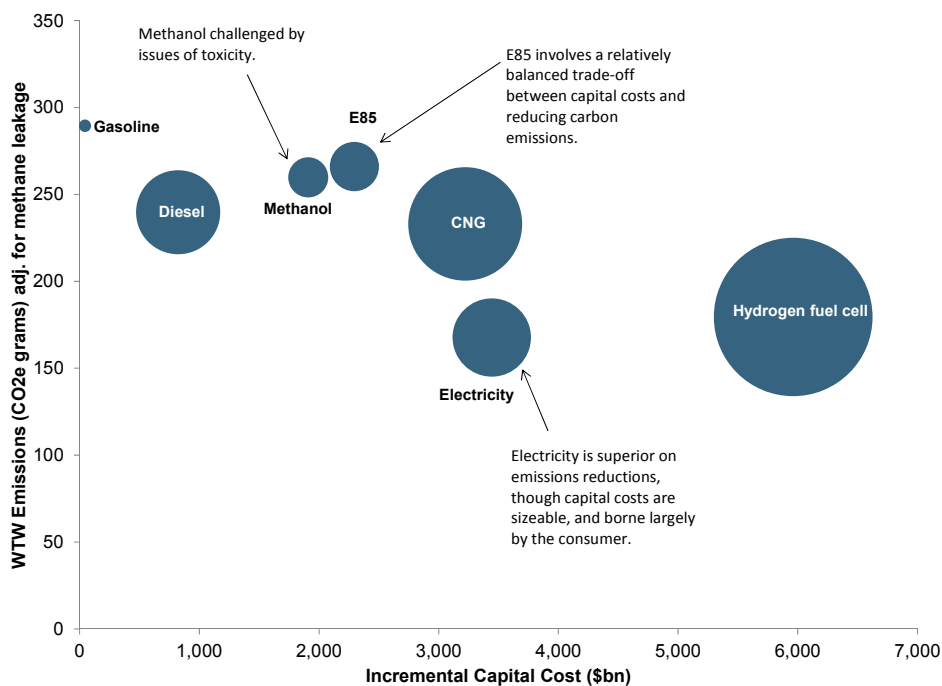
Transmission is where the renewables join the vertical supply chain and where the value of renewables needs to be assessed, as there is usually a significant tradeoff between zero emissions and land usage (particularly is the case with biofuels). To overcome this land constraint, wind and solar are typically built far from residential and urban areas which then requires a significant investment in power line transmission that can create a new set of environmental problems. These transmission issues combined with the fact that wind is typically far more productive at night when demand is low requires delicate matching of renewable capacity with demand to avoid redundancy that already exists with some wind capacity.

As the supply chain moves to the **end user**, upfront capital costs and fuel optionality become the critical issue in minimizing both costs and emissions. On the distribution side there is a need for policy aimed at the coordination of infrastructure development and allowing free fuel choice. With the new technologies come new fuel options such as natural gas-based ethanol where the drivetrain technology already exists, so allowing for more fuel choices would create more demand for natural gas in the transportation sector and help create the confidence needed to build out the distribution infrastructure to deliver natural gas into the transportation sector at prices far below gasoline.

Finally, it is important to emphasize that while we see both natural gas-based ethanol electric vehicles as the superior technologies on a well-to-wheel basis (see Exhibit 15), the two technologies have very divergent investment requirements: ethanol is very front-end-loaded at the upstream drilling and refining stage with little burden on the consumer, whereas electric vehicles require comparatively less infrastructure investment but a much larger investment borne by the consumer. This last point reinforces the point that policy choices in the transportation sector will have a critical impact on investment patterns and ultimately which technology becomes more dominant.

Exhibit 15: Natural gas-based ethanol (E85) and electric vehicles have the best cost/emissions trade off relative to consumer payback time period

Well-to-wheel emissions against capital cost by fuel; bubble size represents years until consumer can payback the excess vehicle cost relative to gasoline



Source: Argonne National Laboratory, EIA, NREI, company reports, Goldman Sachs Global Investment Research

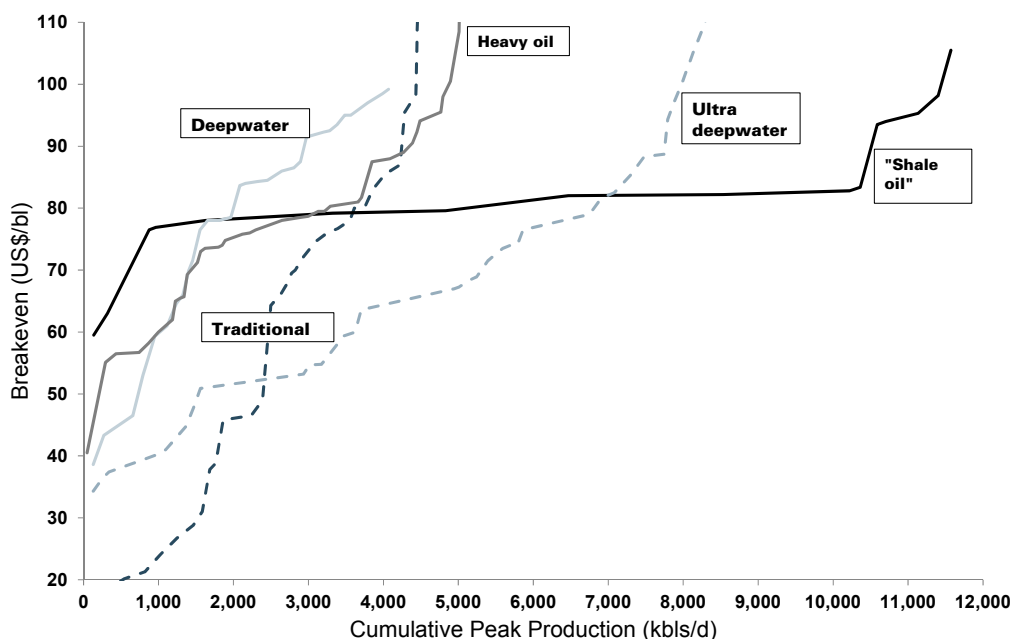
3. Policy needs to promote scalability and diversification in generation

1. *Renewable generating capacity will continue to take market share as technologies improve and as they benefit from policy-backed incentives/mandates, though many of these incentives require a "socialization" of costs. Until centralized electricity storage technology options emerge and become broadly available at volume, technologically-driven limits on scalability exist for renewables (due to intermittency and climate change), making other technology options necessary as base-load resources;*
2. *Cost and environmental concerns may drive a lower reliance on nuclear or coal generation – impacting their scalability – making increasing use of natural gas a necessity as more of a base-load resource, especially given significant scalability advantages;*
3. *Predicting technological advances remains challenging and we recommend a diversified portfolio approach to power generation – but emphasizing the importance of natural gas generation as a source for base-load power and as capable of "solving" intermittency issues created by expanding renewable generation portfolios.*

The most important lesson that we learned over the last decade on the supply side is that not all technologies are scalable and picking the right one is nearly impossible. Ten years ago, oil sands, ultra deepwater, gas-to-liquids and shale were all promising technologies with relatively low costs when done in small scale. However, as the industry scaled each of these technologies up in size, it soon found that only one of them worked with truly large scale – and that was shale (see Exhibit 16).

Exhibit 16: Of the competing new oil production technologies, only shale could be scaled up without a dramatic increase in costs

Breakeven of non-producing and recently onstream oil assets by category, US\$/bbl



Source: Goldman Sachs Global Investment Research

The reason for this was that the other technologies hit unforeseen geological and technological constraints that prevented them from being scaled up at low cost. In contrast, shale was initially considered the least likely technology as the costs were expected to be too high on the oil side, but as it was scaled up on the natural gas side, engineers learned how to reduce the costs substantially on the oil side, leading to the entirely unexpected surge in US oil production.

This same uncertainty in technology also applies to the demand side as well, which is why we emphasize the importance of considering the following issues in designing a successful energy policy:

1. **Scalability.** This not only creates economies of scale to keep consumer costs low, but with the right technologies it also allows for a meaningful reduction in emissions; however, not all technologies are scalable but rather hit a scalable limit, most likely technological that needs to be overcome by engineers, which in the meantime makes other technologies more cost effective to be scaled up.
2. **Diversification.** However, because we do not know which technologies can be ultimately scaled up (just as we did not know about shale), we should diversify our investment across technologies until they hit their scalable limit while engineers either find a solution or the technology is deemed ineffective.
3. **Socialization.** In some cases, a technology such as solar may provide significant benefits to society through reduced emissions but given current technology may not be economically viable such that socializing its costs through subsidies or tax breaks is optimal; however, to the extent that government subsidies for adoption of the technology exceed the cost of rapid adoption of competing technologies or the opportunity cost of using research and development for new future technologies then such subsidies need to be reassessed.

In general, the economics of renewables and other new technologies work up to a scalable limit, but because the scale limit is below the market for other technologies a greater emphasis must be placed upon the truly scalable technologies given current technologies such as natural gas, at least until the technological progress improves. Further, a truly scalable technology can be done without creating negative externalities that generate costs in other parts of the economy, i.e., biofuels turn a carbon problem into an arable land and food problem when the process is scaled up.

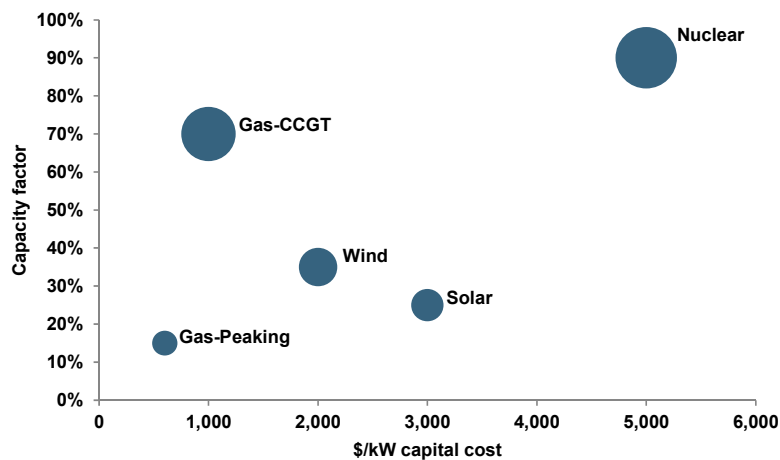
Avoid picking a winner before the engineers do

In many cases scaling up a technology that hits a known constraint requires faith that sometime in the future someone will find an adequate solution to take it to the next level. While we remain positive that engineers will solve the battery problem for electric vehicles, there still exists some uncertainty around the availability of lithium and other rare earth metals. For example, 50% of potential lithium supply reserves are in Bolivia where very little large-scale Lithium mining has been done, so the cost of this production is still relatively unknown – it could turn out far cheaper or far more costly – as scale can change everything. There is also the issue that reserves are even more concentrated than those for oil, potentially creating geopolitical risks.

Nonetheless, many of the cutting-edge technologies that are carbon-free run into far more serious constraints and most will remain niche markets until engineering solves their scalability problem. For example, wind faces the problem that most of the output occurs at night when demand is low such that large-scale battery technology will be required to truly scale up the technology. Intermittency remains a key challenge impacting the scalability of renewables – as these sources have much lower utilization rates than conventional forms of power generation (see Exhibit 17). Unlike nuclear or coal generation, natural gas power plants can ramp up quickly to respond to the potential for wind or solar generation to decline rapidly, intra-day, as their respective resources decline. Accordingly, natural gas generation has a key role to play in a well-diversified, sustainable generation mix.

Exhibit 17: With relatively high utilization rates and low capital costs, combine-cycle gas plants offer significant scalability in the power sector

Capacity factors and \$/kW capital costs by fuel type



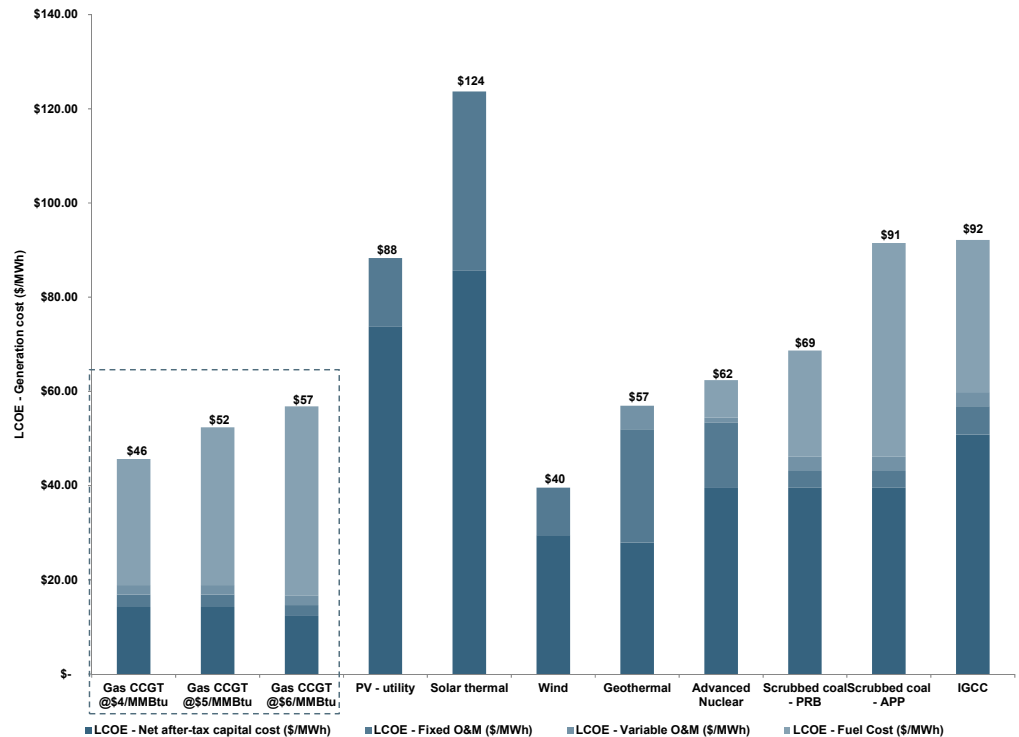
**Size of the bubble represents relative generation levels on identical plant capacity*

Source: EIA, Goldman Sachs Global Investment Research.

Gas-fired generation, due to its low capital or construction costs, emerges as one of the most economic ways for the United States to meet significant increases in power demand –

on cost alone, assuming natural gas prices in the \$4-\$6/MMBtu range – even when incorporating current benefits associated with other forms of power generation, such as tax credits for renewables or government sponsored debt financing for new nuclear. Utilization rates remain much higher for conventional generation sources such as gas fired generation than for many other forms, while the \$/kW installed construction costs will likely remain lower at least for the near and medium term (see Exhibit 18).

Exhibit 18: At natural gas prices up to \$6/MMBtu, new combined cycle plants appear mostly economic versus other forms of new power generation capacity
 Levelized cost of electricity (\$/MWh) – scenario analysis at natural gas prices of \$4 - \$6/MMBtu



Source: Goldman Sachs Global Investment Research.

Nonetheless, the United States can meet increases in power demand driven by growth in the electric vehicle fleet or by other drivers – including a major manufacturing renaissance – through a variety of potential resources, including the development of new natural gas, renewable, nuclear and coal generation capacity. Trade-offs clearly exist and environmental impacts matter – likely limiting some potential options, such as a major expansion of coal fired generation, especially in the near term.

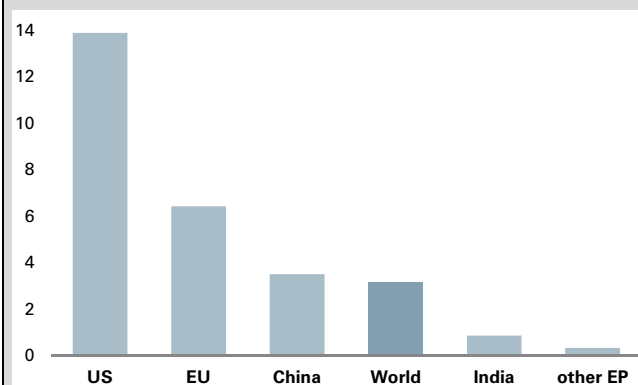
What this suggests is that diversifying across technologies creates more optionality in which technologies will be scalable in the future, as putting all the weight on a single technology is very risky. **While previously we advocated it was policy certainty that encouraged investment in *known* technologies, here policy flexibility through diversification is required to support investment in *unknown* technologies.**

Box 3: The role of coal – Helping to alleviate energy poverty, though environmental impact still a concern

Improving access to electricity is an important development goal. It is no coincidence that countries with low electricity consumption are grouped at the bottom of the Human Development Index table. The causality between development and electricity use goes in both directions: access to electricity impacts education (lighting at night for homework) and health (replace indoor use of solid fuels for cooking and heating) as well as economic activity, while rising living standards create the purchasing power for electric appliances.

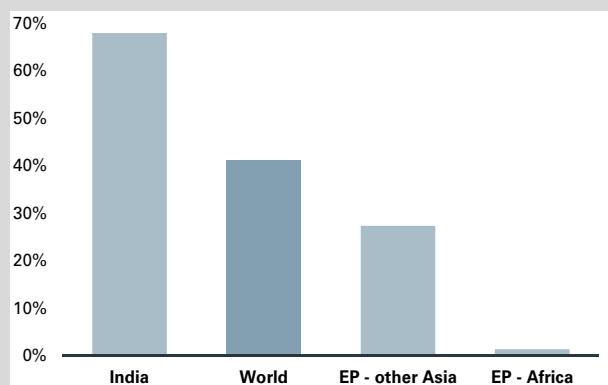
According to the World Bank, 1.7 billion people have gained access to electricity supply in the past 20 years, taking the global electrification rate to 83%, but more progress is needed; New York City (population: 8 million) consumes almost as much electricity as Nigeria (164 million) and Bangladesh (153 million) combined. For these reasons, many development agencies including the World Bank and the United Nations are focused on bringing electricity to the remaining 1.2 billion people who still lack adequate access to electricity supply. Achieving this goal will lead to greater demand for energy, including coal.

Exhibit 19: Significant gap in consumption per capita
Average electricity consumption per capita – MWh (2012)



Source: World Bank

Exhibit 20: India is heavily reliant on coal
Share of coal in power generation (2012)



Source: McCloskey, Goldman Sachs Global Investment Research

Thermal coal is a cheap energy source that is widely available. Coal-fired plants are cheaper to build than nuclear power, and with a few exceptions (e.g., shale gas in the United States) they have lower operating costs than gas-fired plants. Provided that rail and port capacity is available to transport coal from the seaborne market to the plant, commissioning new generation capacity is relatively straightforward. On these merits, and given the absence of environmental regulation that could penalize coal-fired generation in energy-poor (EP) countries, we expect coal to play an important role in addressing energy poverty. India is already a large consumer of coal, but other EP countries lag well behind both in terms of overall consumption and as a share of the fuel mix. Existing and potential projects to build new coal-fired plants in countries ranging from Pakistan to Myanmar will therefore bring electricity supply to millions of people and boost demand for coal, albeit from a low base.

However, many of these regions are also amongst the most vulnerable to climate change and this will undoubtedly shift future investment towards less polluting energy sources. Energy policies such as carbon pricing in China and lending criteria from financing institutions such as the World Bank and the EBRD are likely to lead to a more diverse fuel mix in some markets. India clearly has significant upside for thermal coal but the battle on energy poverty in other regions is likely to have a more limited impact on coal demand.

Five policy questions that need answers to kick-start the demand phase of the revolution

We think the key to reducing uncertainty enough to kick-start the next “demand response” phase of the “shale revolution” is the development of coherent and sustainable policies in five key areas: best fracking practices and water rules, improving pipeline rules, capture of fugitive methane, encouraging natural gas-based ethanol (E85) fueled and electric vehicles in transportation sector and reforms to the power generation sector. These are the “low hanging fruit” issues that we believe that framing well posed questions around could set policy on the path to encouraging long-term confidence in the ability of the energy sector to deliver its potential across North America.

What are best fracking practices and water rules?

We see four key issues related to drilling and completion of shale wells in which industry and policymakers can further work together to promote transparency and environmental stewardship. We highlight examples in which producers in some cases together with policymakers have taken action.

- *Disclosure of chemicals used in hydraulic fracturing.* We believe it is key that there is public confidence the environmental risks associated with the use of frac fluids are acceptable. Hundreds of operators now disclose the components of chemicals on a well-by-well basis on www.fracfocus.org.
- *Reducing surface and air disturbance.* In both rural and urban communities that have seen increases in activity, there remain concerns regarding surface disturbance, contribution from drilling/fracture stimulation on pollution/air quality and traffic/noise that reduce quality of life for local residents. In 2008, the Bureau of Land Management reached an agreement with producers in the Pinedale Anticline in Wyoming to allow year-round drilling in a portion of the play but with more onerous restrictions on surface disturbance, trucking and emissions.
- *Ensuring well integrity to prevent groundwater contamination.* We see a continued need for industry to increase public confidence in well integrity to reduce concerns of groundwater contamination. We view the casing of wells as key, particularly when wells are being drilled through aquifers. We would note that EOG Resources indicated that in 2012 it tested surface casing integrity and conducted annular pressure monitoring of 100% of its operated wells.
- *Measurement and recycling of water supply.* Water disposal and water quality remain an ongoing concern across shale plays, particularly in areas such as the Marcellus Shale where there are limited to no options for drilling disposal wells. Producers such as Cabot Oil & Gas and EQT in 2012 recycled almost all water that flows back from completion. Nevertheless, there remains further opportunity to reduce freshwater withdrawal used for drilling and completion. Before and after drilling, testing of groundwater can help identify areas of non-compliance. Prior to drilling, Cabot gives landowners the option to allow Cabot to test all water sources within 3,000’ of a proposed well at company expense.

How can pipeline rules and regulations be improved?

Oil and natural gas pipelines have faced increasing siting and permitting challenges over the last several years, which has sometimes slowed production and demand development, including the switch to cleaner-burning natural gas. These delays can also increase costs for the pipeline operator. We see three key areas for improvement in the process:

- *Better federal-state-local coordination.* Interstate pipelines must receive approval from the Federal Energy Regulatory Commission (FERC) for new construction or

modifications. However, many pipelines also require other federal and state permits, which can often cause delays in construction and/or increase costs. FERC has the ability to set deadlines for state permits, but lacks the authority to enforce these deadlines. We recognize that new pipeline construction in particular will always require state and local approval and must respect environmental, historical, or personal property issues. However, we believe better adherence to permitting deadlines can improve the pace and size of infrastructure investment and efficiency of the gas/oil transportation network.

- *Presidential permit.* Pipelines which cross the US border require a “Presidential Permit” whose jurisdiction falls under the Department of State. The well-documented delays to the Keystone XL oil pipeline from Canada to the United States highlight the challenges in this process – operator TransCanada originally filed its permit in the fall of 2008, and has yet to receive a decision on its permit. We believe better coordination between state and federal authorities, and increased clarity on the potential scope of review as part of the National Interest Determination, would improve the process and allow for more timely decision-making on projects that cross the border.
- *Improved gas-electric coordination.* A large portion of the growth in natural gas demand over the last several years, and into the future, will come from power generation. However, in many unregulated power markets such as New England, merchant generators have little incentive to contract for firm capacity on new natural gas pipelines as they do not have guaranteed recovery of those costs. We believe mechanisms to encourage price signals to contract for gas pipeline capacity can encourage increased investment in infrastructure.

What are optimal strategies for capturing fugitive methane?

Methane emissions have attracted increased attention in discussions around greenhouse gases given methane is 20 times more efficient than carbon dioxide at trapping radiation in the atmosphere. The EPA estimates methane accounted for about 9% of total GHG emissions in 2012. We see three main areas where industry and policymakers can take action to reduce methane emissions.

- *Better measurement.* The EPA estimates roughly 6.2 teragrams of methane emissions in 2012 from the natural gas system, which equates to 323 billion cubic feet or around 1.3% of total production. However, other studies estimate methane emissions in the 3-6% range from oil and gas production. A key measurement question involves the “bottom-up” methodology from EPA, which measures emissions from individual systems on the ground in a continuous manner, versus a “top-down” approach which measures emissions via flights over producing regions on a one-off basis. Forthcoming data-intensive bottom-up and top-down studies in producing regions, transmission corridors and consumption areas should increase understanding of the true sources and nature of methane emissions. Industry and policymakers should encourage increased focus and investments on measurement tools and analysis to understand the sources of methane emissions and means of capture – in other words, “measure it to manage it.”
- *Upstream – improve completion techniques.* Based on our discussion, we believe exploration and production companies could reduce methane emissions by using larger-diameter pipe when completing natural gas wells. Welding more/larger pipe makes for fewer connections and less leakage. Importantly, the upstream industry should embrace these techniques, as they are potentially returns/profitability-enhancing as they increase volumes/revenues, unlike midstream/downstream operators where the commodity is a pass-through to customers.
- *Midstream/downstream – accelerate/improve integrity programs and financial recovery.* Most long-haul pipeline and local gas distribution companies have instituted multi-year pipeline replacement programs to improve the safety and reliability of their

infrastructure. This trend has accelerated in recent years due to some high profile incidents, such as the explosion in San Bruno, California in 2010. We believe improving the integrity of the system via pipeline replacement and monitoring has the ancillary benefit of reducing methane emissions, since newer plastic pipelines at the distribution level have a lower leakage rate, and increased monitoring at the large diameter pipeline level can also reduce emissions. From a regulatory standpoint: (1) state regulators could encourage increased investment in pipeline replacement programs, and more “real-time” recovery of and on those capital investments, and (2) federal regulators like the FERC could consider authorizing recovery of and on interstate pipeline replacement and monitoring capital via annual automatic tariff increases, similar to a recent ruling for the NiSource pipeline system, rather than a formal rate case process.

How can natural gas-based ethanol (E85) fueled and electric vehicles be encouraged in the transportation sector?

Today’s US light vehicle fleet is not positioned to consume large quantities of ethanol or E85. OEMs do not allow new vehicles to run on fuel with more than 10% ethanol, due to industry concerns over engine damage, particularly related to fuel lines and sealing systems. In addition, while it is technically possible to convert existing cars’ gas engines to run on E85, anti-tampering laws prevent this from happening in all but very few cases. We offer 2 specific policy recommendations to support natural gas based ethanol demand and one to support Electric vehicle demand:

- *Mandate, or further incentivize flex fuel vehicles:* Because the technology has already been developed and fully tested in the US, manufacturers can significantly increase its installation and usage rates at negligible additional cost. More consistent use of flex fuel technology will put the industry in a better position to evolve its usage of other alternative fuels. Another area of policy support could be subsidizing the expense of converting some of the nation’s 121,000 gas stations to offer ethanol, which comes at a cost of \$300,000 per island on some estimates.
- *Make the Renewable Fuel Standard more flexible:* Even with more E85 vehicles it will take time to change the characteristics of the vehicle fleet and generating near-term demand of natural gas based ethanol we would likely require some flexibility from the Renewable Fuel Standard to allow it to be used along with renewable based ethanol. This is because given the “blend wall” of 10% for most vehicles we are already not consuming the 15bn gallons of renewable ethanol targeted by the RFS.
- *For EVs, policy can step in to shorten the payback period:* While the returns on an EV investment are economically sensible at a 17% ROIC, this translates into a payback of six years, which is a bit on the long side for most car buyers. This payback should come down over time as scale and competition ramp up, but in the interim the government could provide capital to fund the estimated incremental cost of \$8,330 for an EV (keeping the buyer’s monthly payments similar to a conventional ICE) and then recoup this by taking a portion of the annual savings through taxes (as EVs cost much less to operate than gas cars). This would still leave the consumer with lower net transportation costs, and have a clear GHG benefit.

What reforms in the power generation sector should be instituted?

The US power sector, given lengthy investment timeframes, needs more certainty from various regulators, policy makers and stakeholders. Multiple policy making bodies significantly impact the long-term design and structure of US power generation. Federal utility regulators and regional grid operators play a key role in designing and monitoring competitive regional power markets, while state utility regulators still oversee, in certain areas, the changing shape of power generation. Environmental agencies, federal and state, shape the rules and regulations that impact what types of generation may need

incremental controls or face cost challenges. Congress and the Administration remain key – given their role in the development and growth of emerging technologies, such as renewables, energy efficiency, nuclear and even coal technologies, through tax and other related incentives that stimulate investment.

- *Revising market designs and structures in several competitive power markets that will encourage use of long-term contracts – to provide more certainty for developers and owners of power plants – and to lower costs, especially for financing.* Multiple US regional competitive power markets, including the major ones in the East, MidAtlantic and parts of the Midwest, maintain designs that hinder the use of long-term contracting for new plants or even for existing ones. This should change, via coordinated actions by state and federal power or utility sector regulators and stakeholders, to adopt market structures that enable generators to enter multi-year deals in these markets.
- *Providing long-term certainty on economic incentives and mandates for potential new renewable, clean coal and nuclear power plants.* Over the last 10-12 years, the US created tax incentives and state mandates that drove significant development of new renewables – but we note every few years, these incentives expire, creating a “boom/bust” cycle for renewable development, until Congress passes a new short-term extension, like the one that exists through 2015 now for federal renewable tax credits. We need multi-year certainty – given the lengthy time horizon needed to site, develop and build new plants – not just renewables, but also emerging clean coal or even nuclear ones.
- *Regulatory visibility for environmental rules – at the state and federal levels – will enable power companies to plan for future changes in their generation mix.* Multiple rules, both state and federal, continue to emerge that will impact clean air and clean water requirements from existing and potential new power plants. Increased certainty regarding the timeline and implementation of these rules – as well as increased coordination across federal and state regulators – would enable power companies operating in multiple states to design and implement generation changes that could serve entire regions – but they need further detail on state and federal requirements before they can fully plan their generation portfolios.

Over the last 10-15 years, the United States witnessed a significant growth in renewables, triggered by state portfolio standards and federal/state incentives. While continued renewable growth will come, due to their intermittency issues there will be an increasing need for fast-starting gas-fired generating units that can ramp quickly when renewables go offline. Legislation to stimulate renewables, clean coal or even nuclear technologies via tax or other incentives tends to have short time horizons, creating significant investment uncertainty every few years after legislation passes. Efforts to stimulate emerging technologies need multi-year provisions to create longer cycles (critical especially for renewables such as wind) and also therefore impacting gas plant development that should “back-stop” additional renewables.

Policy focus 1: Reducing uncertainty to encourage sustained industrial development

How significant could shale gas be for US chemical production?

According to data from the American Chemistry Council, there are currently more than 100 new US chemical projects valued at \$96bn scheduled to take advantage of low-cost US shale with more than half (55%) of these projects proposed by non-US companies.

Most of these projects are being built with exports of finished products in mind, which could help improve the US trade deficit. The American Chemistry Council expects the chemical trade surplus to escalate from \$800mn in 2012 to nearly \$30bn in 2018 with market share gains from other key developed market production centers such as Europe and Japan. Almost all of the growth in the trade surplus would come from basic chemicals (petrochemicals) whose export surplus is expected to grow \$25bn over that time period.

This wave of investment could provide more than 500,000 construction and capital goods manufacturing jobs through 2020 to execute all this construction. For context, the US chemical industry currently employs just under 800,000 people. Additionally, these are some of the best-paying jobs in manufacturing with average hourly wages over \$20/hour.

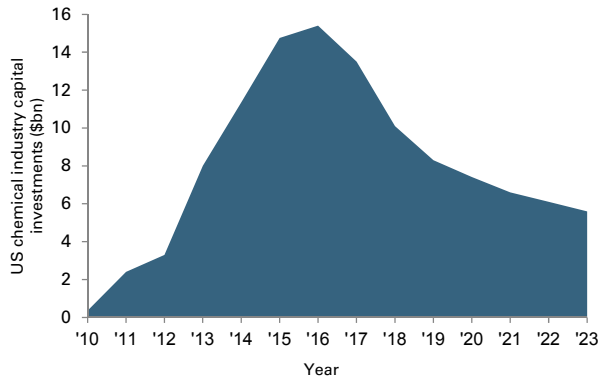
We believe extending the current investment excitement beyond the near-term requires increased confidence in future energy prices and supplies. Should US manufacturers become comfortable that current relative cost curves can be sustained, even after the current wave of expansion is absorbed, we would expect a second reinvestment wave, and all its attendant domestic benefits, to occur.

As a theoretical question, it is interesting to explore just how much global market share US producers could take through low-cost capacity additions. We attempt to answer this question for three of the largest commodity chemicals – ethylene, chlorine/caustic, and methanol – to get a sense of the upper-end of the theoretical bounds of harnessing shale.

For these three products alone, **over \$350bn of capital spending (2013 US dollar terms) in the United States would be needed to fully take market share from disadvantaged regions.** Furthermore, from that point another \$20bn of capital spending per year would be needed to build capacity to supply 100% of global demand growth for these three products. These figures dwarf the already-announced investments depicted in Exhibit 21, but are unlikely to be fully realized for a number of reasons, which we discuss below.

Exhibit 21: While a wave of chemical industry capex is expected to peak in 2016...

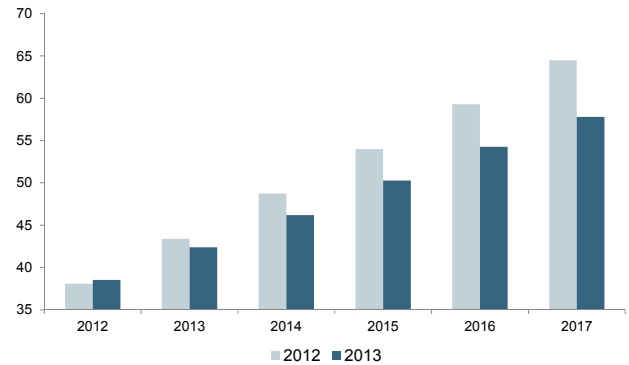
US chemical industry capital investments, in \$bn



Source: American Chemistry Council

Exhibit 22: ...projects often get delayed relative to expectations

Expected US chemicals industry capex, \$bn



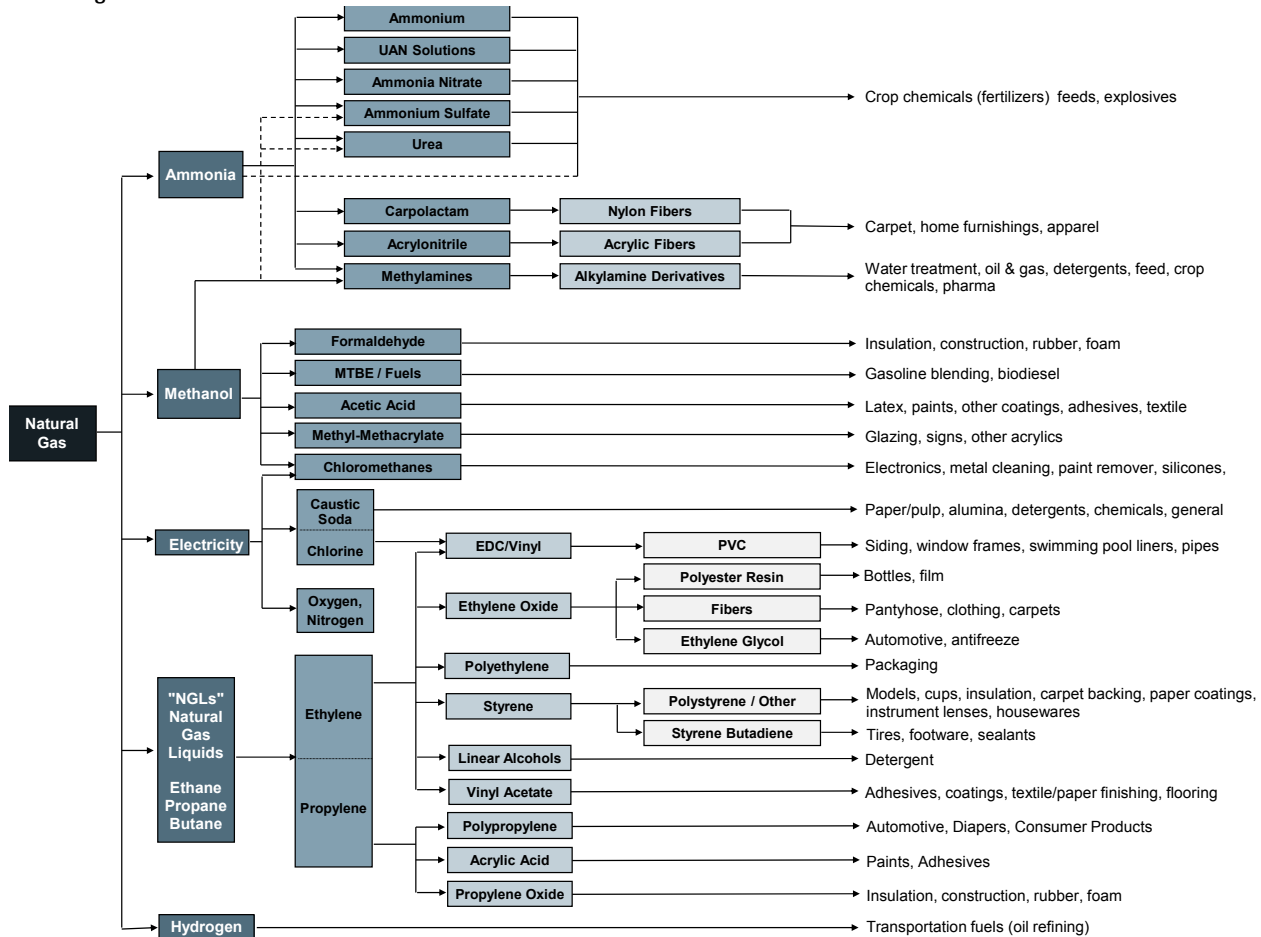
Source: American Chemistry Council

Ethylene

Ethylene is a 300bn pound global market growing slightly faster than global GDP. It is a building-block chemical used to make most plastics as well as diverse products from anti-freeze and de-icing fluid to tires to polyester and acrylic fibers, as shown in Exhibit 23.

Exhibit 23: Natural gas plays a major role in the chemicals industry

Natural gas flow chart

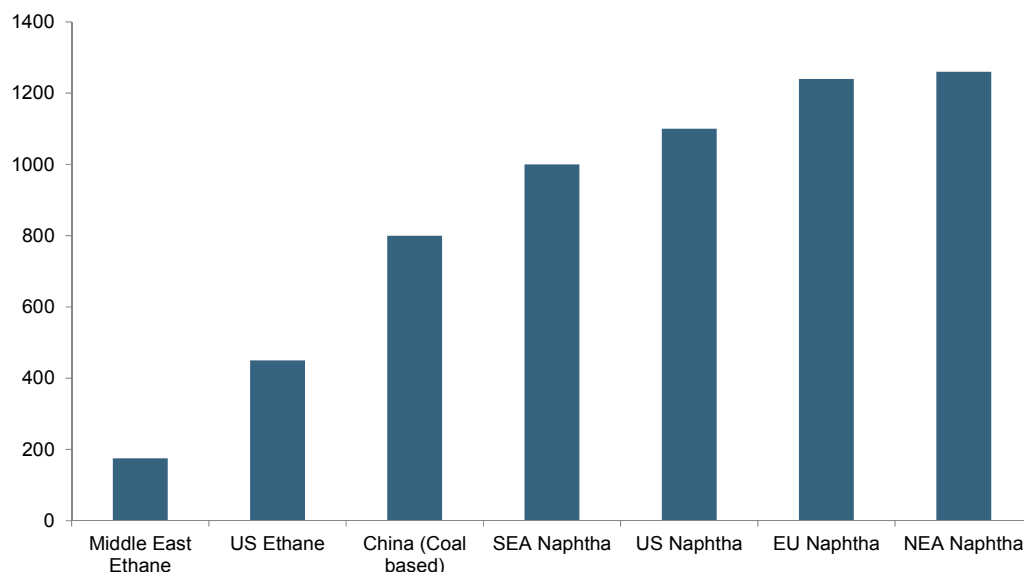


Source: American Chemistry Council, Goldman Sachs Global Investment Research

US capacity, which is advantaged by shale gas, currently accounts for 19% of global production. Another 30% of global production (mostly Middle East) is cost advantaged, similar to the United States. This leaves around 50% of global production susceptible to US market share gains, as shown in the global cost curve in Exhibit 24.

Exhibit 24: Global ethylene cost curve

Ethylene breakeven costs by region/feedstock (2013), in US \$/tonne



Source: IHS Chemical

Because natural gas and NGL production growth in other cost-advantaged regions (e.g., the Middle East) is limited, there is little competitive threat from new supply from these regions. This provides US producers with an opportunity to add capacity to meet the world's growing demand as well as to take market share from high-cost regions such as Europe and Asia.

We forecast global ethylene demand to grow around 11bn pounds per year, which is 19% of the current US installed capacity of 57bn pounds. In other words, the United States could increase its ethylene capacity nearly 20% each year just to supply global demand growth without displacing overseas production.

Taking this exercise to its theoretical limit, the United States could also displace the existing 146bn pounds of disadvantaged global production. **This would require nearly quadrupling the US ethylene industry from 57bn pounds to 203bn pounds.** While this is highly unlikely for a number of reasons, we believe that it shows the vast potential for further ethylene projects.

We estimate the current capital expenditure for ethylene at roughly \$1.00 of capex per pound of capacity. Capital spending for necessary derivative capacity is currently another \$0.75 per pound. We would also expect significant cost inflation as multiple projects compete for limited materials and labor, made worse by the US restrictions on work visas. As a result, the current \$1.75 per pound capital cost could easily grow to \$2.00 per pound in coming years.

Using a \$2.00 per pound capital cost estimate on the potential 146bn pounds of new capacity to fully exploit the cost advantage would imply a further \$292bn of capital investment in the US for ethylene alone. Additionally, if US producers were to try to capture all of the global demand growth, that would necessitate a further \$22bn per year of investment into perpetuity.

Chlorine/Caustic

The electrolysis of brine (salt water) to produce chlorine and the by-product caustic soda is referred to as chlor-alkali production. For every ton of chlorine produced, 1.1 tons of caustic soda are made as a by-product. This combination of chlorine and caustic is referred to as an Electrochemical Unit (ECU).

The global chlor-alkali market is 66mn tons growing in line with global GDP growth. US capacity, which is advantaged by shale gas, is 15mn tons or 23% of global demand. There is limited other advantaged capacity globally and we estimate 70% of global capacity is higher-cost than US capacity.

Applying the same theoretical exercise as we did with ethylene, **US capacity could quadruple from 15mn tons today to 60mn tons** to fully capture this disadvantaged capacity. Similar to ethylene, there are a number of reasons why this is impractical, but it still illuminates the potential opportunity.

We estimate the current capital expenditure for chlor-alkali at \$1,150 per ton of capacity. **Using this as a benchmark would imply over \$50bn of capital investment in the United States for chlor-alkali alone.** We would also likely expect further investment downstream of chlorine into the vinyls chain (EDC/VCM/PVC) in order transform chlorine into an exportable form. This downstream investment could double the \$50bn initial chlor-alkali capital spending.

Methanol

Methanol is a 66mn ton global market growing 2x-3x global GDP growth. Much of the global growth is being driven by China, where numerous projects are underway to turn local coal into methanol for use as transportation fuel or as a feedstock for ethylene (and other chemicals) production.

As we discussed above, the US methanol industry was badly damaged in the 2000-2010 period due to record high natural gas prices and lackluster domestic demand. As a result, only 4% of global capacity is in the United States today. We estimate another 72% of global production is cost-advantaged, including stranded-gas locations in the Caribbean and coal-gasification projects in China.

This still leaves roughly 25% of global production as at-risk for market share gains from the United States. Furthermore, the faster growth rate for methanol demand (vs. other commodity chemicals) provides more opportunity for US capacity additions. **Therefore, the United States could theoretically grow its methanol capacity 500% from 3mn tons to 19mn tons to capture 25% more market share.** From there it could add 5mn tons per year more capacity to capture all of the global demand growth. Again, we view this as impractical for a number of reasons, but it illustrates the opportunity.

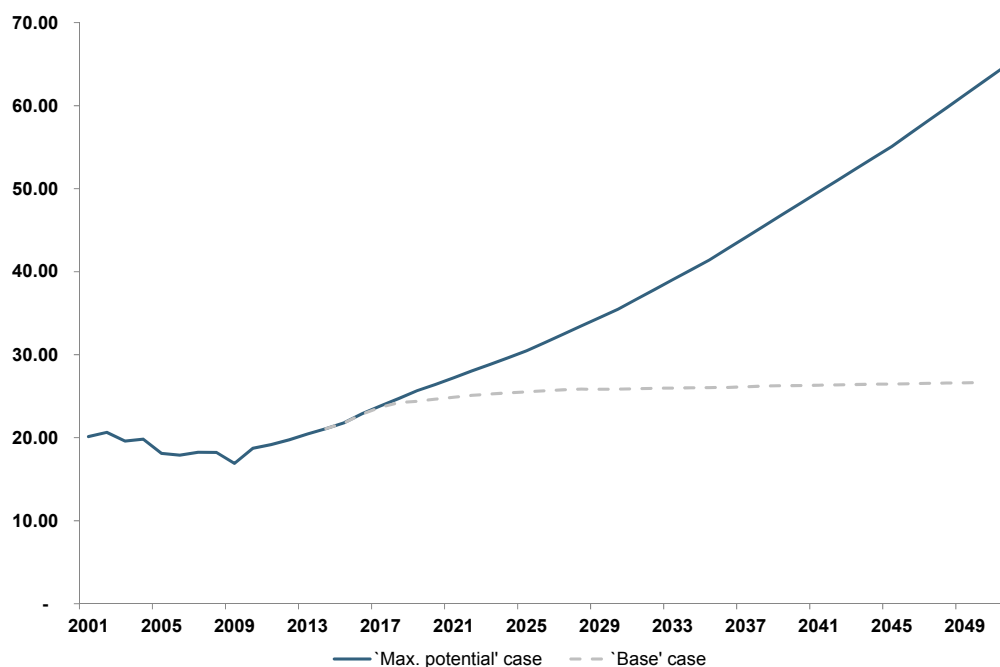
We estimate the current capital expenditure for methanol at \$900 per ton of capacity. **Using this as a benchmark would imply \$14bn of capital investment in the United States for methanol to take share from disadvantaged regions. It would also imply over \$4bn per year in capital expenditure to capture 100% of global demand growth.** Further downstream capital expenditures would be likely, but would be of smaller size.

The upside can be exploited with policy clarity

Given the competitive advantage the United States now enjoys across a wide array of energy-intensive manufacturing sectors, the size of the potential opportunity to kick-start a North American manufacturing renaissance is demonstrably large. However, this impressive potential compares against a rather lackluster base case projection for industrial demand as published by the EIA in its 2014 Annual Economic Outlook (see Exhibit 25). The key to this divergence between the potential and the projection is the policy environment.

Exhibit 25: The potential upside is meaningful, but policy is needed to make it reality

GS estimated maximum potential industrial gas demand vs. base case (EIA growth projections through 2040, extrapolated beyond), Bcf/d



Source: EIA, Goldman Sachs Global Investment Research.

To access the potential that North America has to exploit its cost advantage and increase market share, several current uncertainties need to be addressed to give business the confidence that the current competitive advantage is sustainable.

Given the long-term, irreversible nature of these investments, management make investment decisions based on a 20-30 year view of profitability rather than just current margins. With questions currently raised over the future evolution of policies to address fracking and wholesale exports of US LNG, the clarity over natural gas prices and availability of supplies which is necessary to encourage investment is clearly not yet in place. Until these issues are addressed, the chemicals industry will likely begin to face the same challenges that US refining now faces, where uncertainty over the export ban has paralyzed investment.

Further, while it is currently not practical to hedge margins out on a long-term basis, which itself may discourage investment, we view the underlying logic here as somewhat circular. Policy changes which encourage business confidence and encourage investment would likely materially increase market liquidity for longer-term hedging, further reducing

uncertainty. Therefore, we see policy as capable of kick-starting a virtuous cycle of reduced uncertainty and increased ability to hedge longer term risks.

Clarity over price is not the only thing that matters before business can be confident of sustainably embarking on a new revolution in manufacturing. Importantly, clear environmental policy that anticipates this potential change must be laid out to present a clear vision of the future. For instance, air quality rules and carbon capture policies could be managed to actively develop the vision of a sustainable North American manufacturing renaissance.

Finally, as we highlighted above, uncertainty still exists over immigration policy that is needed to attract the skilled labor in the near term to fill the plants and help to grow the industry.

We believe that these uncertainties can all be managed effectively through a coordinated effort between business leaders and policymakers. We believe that there is material upside to ensure that the announced \$96bn of project spending currently forecasted by the American Chemistry Council does not stop there, but continues to flourish into a full renaissance in North American energy intensive manufacturing.

Policy focus 2: Optimizing costs and emissions through the supply chain for light vehicle transportation

In this section, we evaluate seven different fuel options for North America, looking at (1) required investment to convert the light vehicle fleet, (2) variable cost and payback, and (3) well-to-wheel emissions. Our conclusion is that among the liquid fuels (gasoline, diesel, ethanol and methanol) natural gas based ethanol is promising with a good payback at current feedstock prices, and well-trodden flex fuel technology that lowers consumer switching costs. Negatives are sizable required investment in refining and extraction, and the need to control methane leakage to see any sort of CO2 benefit over gasoline. Among the remaining alternatives (CNG, EV and fuel cells) EVs look most attractive, with lower upstream investment cost, the largest CO2 benefit, and cheap fuel on a gallon-equivalent basis. Negatives are a high investment cost to the consumer driving a payback of six years that is good but still high in the auto world. With considerable uncertainty in the landscape for transportation fuels, policy and technological developments are likely to have an outsized impact over the next several years.

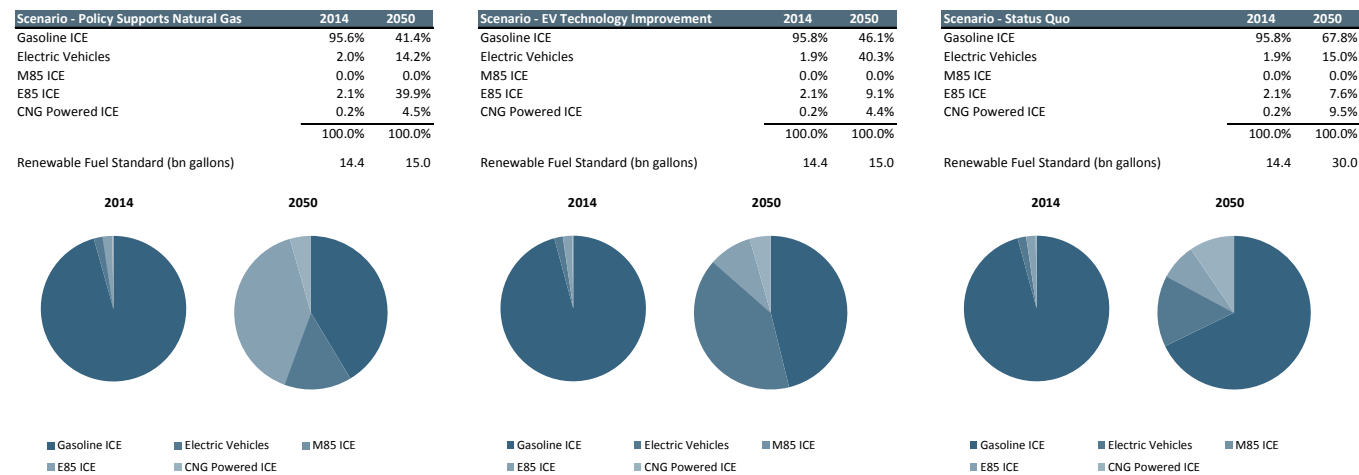
Exhibit 26: Among the transportation fuel options, ethanol and EVs look like the most viable alternatives to gasoline
 Cost-benefit snapshot of switching the light vehicle fleet to different fuel options

		Decision Factors						Practical Implications	
		Emissions	Cost	Energy Density	Upstream Investment	Downstream Investment	Total Incremental Investment		Payback Period
		CO2g per km	\$ per Gal eq	Kg/m ³	\$ bn	\$ bn	\$ bn		years
Fuels	Gasoline	289	\$3.33	750	NA	NA	NA	NA	Status quo remains
	Diesel	240	\$2.86	832	\$363.3	\$459.6	\$822.9	6.8	Low incremental cost, modest emission benefit, slightly long payback
	Ethanol	266	\$3.10	786	\$2,128.6	\$167.2	\$2,295.8	2.3	Moderate cost, small emission benefit, fast payback period
	Methanol	260	\$2.76	605	\$1,616.4	\$293.8	\$1,910.2	1.5	Toxicity/safety risks, small emission benefit, fast payback period
	CNG	233	\$2.20	0.8	\$661.0	\$2,560.3	\$3,221.3	12.4	Good emission improvement, low energy density, long payback
	Hydrogen	180	\$1.87	0.1	\$527.5	\$5,433.3	\$5,960.8	24.0	Highest cost to implement, longest payback, good on emissions
	Electricity	168	\$0.85	Low	\$1,222.9	\$2,220.5	\$3,443.4	5.9	Highest emission benefits, lowest cost per km, slightly long payback
			Good		Neutral		Bad		

* Upstream is defined here as 'extraction', 'refining/conversion/generation' and 'transportation/pipeline'. Downstream is defined as 'retail distribution' and 'consumption'.
 **NA = Not applicable.

Source: Goldman Sachs Global Investment Research

Exhibit 27: The US transportation fuel landscape is far from established; we explore three probable scenarios
 Current and projected fleet powertrain mix under various scenarios



Source: Goldman Sachs Global Investment Research.

With natural gas-based ethanol and EVs looking like the most promising alternatives to traditional gasoline, we outline two potential upside scenarios which we believe reflect realistic adoption rates of these powertrains under appropriate policy support and contrast against a “status quo” scenario involving no significant change in the policy landscape (see Exhibit 27). **We note that in all cases the characteristics of the fleet would change very gradually given the long replacement cycle for vehicles (which can last 20 years), and long powertrain product cycles of 7-10 years.** So that even if EVs were an easy choice today, the earliest sales of 100% EV would be in 2024, and changing the mix of 250mn vehicles on the road would take even longer. As such our projections look out to 2050, a timeframe over which larger fleet changes can happen.

Summary of three scenarios

1. **We have policy support for natural gas.** As we argue in more detail below, the economic rationale for using natural gas-based ethanol already exists given a relatively low payback of two years. But in this upside case policy tips the balance in a multitude of possible ways: (1) mandating flex fuel vehicles, (2) supporting investment for drilling and refining, or (3) improving the already-attractive payback through tax subsidies relative to gasoline, on the grounds of the lower cost to the consumer and possibly lower well-to-wheel emissions under an ethanol-fueled autos market, as we discuss in greater detail below. Under these supportive conditions we could see ethanol (E85) powertrains making up 40% of the fleet 2050 from 2% today. This would imply peak light vehicle natural gas demand of 6.6 Tcf, equivalent to approximately 30% of today’s production.
2. **EVs gain traction.** In this scenario, electric vehicles become the technology that wins out over gasoline. EVs already have a meaningful efficiency advantage over ICEs, with the main drawback being the upfront investment cost. Here we assume the catalyst for accelerated adoption is more of a reduction in cost than policy, though government could potentially continue to play a role in subsidizing the cost of ownership such as extending the Federal buyers tax credit to accommodate higher volumes. Moreover, EV investments currently have a positive present value, such that lower marginal electricity costs ultimately justify the cost of the vehicle. However, consumer payback horizons are usually relatively short-term in the autos industry, meaning that the

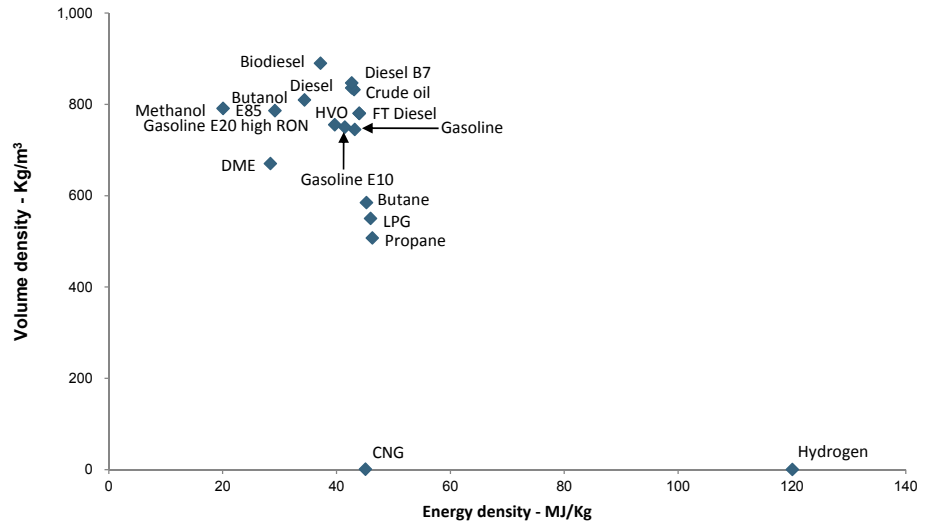
ultimate financial benefits are not always reaped. We see a possible role for government here in helping to smooth the cost of EV ownership to the consumer, for instance by helping to partially finance the cost of the vehicle in exchange for higher incremental taxes on electricity. While OEM product development departments have EVs hitting 10% of sales by 2025 to reach 52.5 MPG CAFE standards, this case would represent a faster adoption rate, ultimately pushing EVs to 40% of the fleet by 2050. As discussed in more detail in the section "Policy Focus 3" on scalability, this would imply 519,000 GWHs of incremental electricity generation and 1.6 TCF of incremental gas demand. Part of the relatively low incremental gas demand stems from the fact that under our base case we assume only 40% of the new generation capacity is natural gas-driven, with the balance being renewables.

3. **We keep the status quo.** Here we assume no meaningful change in government policy and a fairly slow decline in battery costs per KWh. In this somewhat pessimistic case EVs become 15% of the fleet by 2050 (18% of sales). While we still have E85 vehicles representing almost 10% of the fleet by 2050, this is mostly to meet long-term RFS targets for 30bn gallons of renewable fuels, so only a small part of this ethanol would actually be natural gas-based. In the two previous cases we use a much lower RFS target of 15bn gallons as we believe a good case could be made for not increasing the target if the mandate of energy independence and/or emission reductions is largely met through EVs or natural gas-based ethanol.

Gasoline and diesel engines are popular for a reason

Before looking at the specifics of cost and investment it is important to consider some of their key physical properties. As we see from the x-axis in Exhibit 28, looking at energy density by weight (MJ per Kg) diesel and gasoline screen well but so do CNG and hydrogen. The difficulty is it takes a lot of space to store a Kg of natural gas and H₂, so looking at density by volume (kg per cubic meter as shown on the y-axis) CH₄ and H₂ pose a unique challenge that increases the cost of their use. There is also a difference in density among liquid fuels (it takes 1.47x and 1.96x the volume of ethanol and methanol to equal a gallon of gasoline), but this matters more from a practical side than a regulatory side as CAFE MPG standards are currently very favorable for ethanol vehicles as auto makers get to divide the mileage by 0.15 (this is weighted 50/50 with the gas MPG if it is a flex fuel vehicle). Non-liquid fueled vehicles like CNG and EVs get to use an "energy equivalence factor" for the MPG rating.

Exhibit 28: Low energy density by volume increases the cost of using H2 and CH4
 Energy density by weight and volume



Note:
 Gasoline E10 is 10% ethanol and 90% gasoline.
 Gasoline E20 is 20% ethanol and 80% gasoline; RON - Research Octane Number.
 Diesel B7 contains 7% of biodiesel.
 Fischer-Tropsch (FT) diesel is synthetic fuel produced from conversion of natural gas into a diesel fuel.
 HVO is Hydrotreated Vegetable Oil.
 DME (dimethyl ether) is a clean-burning, potentially renewable fuel.

Source: Joint European Commission

A well-to-wheels assessment of North America fuel options

In Exhibits 29-36 we look to compare seven different fuels in terms of their 1) investment requirements, 2) variable costs per gallon equivalent, and 3) Co2 emissions on an “entire lifecycle” basis from extraction and refining, to transportation and then to distribution and consumption. To make each snapshot comparable, we evaluate the implications of replacing **all** 250mn light vehicles on the road in the United States at once with alternatives to gasoline. We look at fleet conversion and investment costs as they stand today, understanding that technology improvements could significantly reduce the burden of changing fuel types in the future.

The investment requirements

Not surprisingly, given the size of the US vehicle fleet the investment costs in this exercise are immense. At first glance a few key conclusions emerge:

- **For liquid fuel alternatives** like methanol and ethanol much of the investment takes place at the front-end in drilling and refining to deliver the nearly 28 Tcf of natural gas demand which we estimate would be required to support the US fleet. Part of this is due to the fact that in the conversion of natural gas to methanol/ethanol one loses 40% of its BTUs, requiring more natural gas drilling than if one were using CNG, for instance. While the \$2.1trn and \$1.6trn refining/drilling investment shown in Exhibit 29 for this stage is an exercise and not a forecast (as it represents the outlays required to convert all vehicles to methane based liquid fuels at once), it underscores that facilitating the sizable investment would be the clear policy focus. **On the flip side, comparatively smaller investments are needed on the consumer/retail end**

especially for ethanol where there is an ability to leverage existing distribution infrastructure and where flex fuel technology is quite simple and cheap to deploy.

- **For EV, fuel cells and CNG** the profile is the opposite, quite a bit less investment is needed at the front end. We estimate outlays of \$718bn, \$388bn, and \$452bn on a similar fleet basis for natural gas production, electricity generation and hydrogen production – large investments but below those of liquid fuels. **The big expenditure is at the back end for the increased powertrain investment** where we estimate consumers would have to spend \$2.1 trillion, \$5.1 trillion and \$1.8 trillion to upgrade to EV, Fuel Cells, and CNG, at today's prices for the technology. The primary element here from a mass market adoption point of view seems to be less about policy and more about getting the cost down, though government subsidies likely continue to play a meaningful role for early adoption.
- **From a distribution perspective**, the cost of converting the nation's 121,000 gas stations would be cheapest for ethanol at \$91bn where industry participants have suggested to us a cost of \$300,000 per island (we assume 2.5 islands per station). For methanol (which is more corrosive and has higher RVP volatility), the cost could be as high as \$550,000 per island for a total cost of \$167bn. These estimates are dwarfed however by CNG, for which industry sources estimate \$1.5mn-\$2mn per island and hydrogen (\$3.4mn per station), for estimated outlays of \$530bn and \$360bn.

Exhibit 29: Total investment costs are largest for Fuel Cells, EVs, and CNG
Full lifecycle investment requirements \$bn

		Incremental investment (billions)						
		Gasoline	Diesel	Ethanol	Methanol	Compressed Natural Gas	Hydrogen fuel cell	Electric Vehicle
Well	Extraction	NA	\$ -	\$ 829	\$ 829	\$ 452	\$ 225	\$ 80
	Refining/conversion/generation	NA	\$ 363	\$ 1,281	\$ 768	\$ -	\$ 163	\$ 718
	Transportation/pipeline	NA	\$ -	\$ 19	\$ 19	\$ 209	\$ 139	\$ 425
	Retail distribution	NA	\$ 3	\$ 91	\$ 167	\$ 531	\$ 361	\$ 110
Wheels	Consumption	NA	\$ 457	\$ 76	\$ 127	\$ 2,029	\$ 5,072	\$ 2,110
TOTAL		NA	\$ 823	\$ 2,296	\$ 1,910	\$ 3,221	\$ 5,961	\$ 3,443

Source: Goldman Sachs Global Investment Research, company reports, EIA, N.R.E.I.

From a payback perspective, ethanol/methanol and EVs look most attractive

Of course just because something costs a lot does not mean it's not worth doing. Our payback analysis in Exhibit 30 shows that despite the big upfront investment for **EVs** at the consumer-end (\$2.1trn), the estimated \$360bn in fuel savings per year would imply a p.a. return of 17%, attractive from a cost of capital perspective but equating to a payback of six years, still a bit high for mass market adoption (the OEM rule-of-thumb is closer to two years). **CNG** comes in at an 8% return (13-year payback) which relegates the technology to fleet buyers until the incremental cost (\$9,000-\$12,000 for a light truck, \$7,000-\$9,000 for a car) can come down. Even further off are **fuel cell vehicles** with a payback of 24 years benchmarking off of Toyota's 2015 FC, which is set to price at about a 20k premium to a Camry.

Ethanol and methanol have the best paybacks from a consumer perspective (2.3 and 1.5 years) given the relatively low upfront additional cost for the vehicles. Given the aforementioned corrosiveness, toxicity and high vapor pressure of pure methanol we tend to discount it. With potentially good returns for consumers and a well-understood flex fuel technology, natural gas-based ethanol seems like a viable option. As of now there is little refining capacity for this in the United States (Celanese has built some capacity overseas). While a move to E85 vehicles would help generate demand for this over time, to generate near-term demand we would need to see some flexibility from the RFS to allow natural gas-based ethanol to be used along with renewable-based ethanol. This is because given the blend wall of 10% in many vehicles we are already not consuming the 15bn gallons of renewable ethanol targeted by the RFS.

Exhibit 30: Ethanol, methanol and electric vehicles offer the best paybacks

ROIC and payback on consumer investment

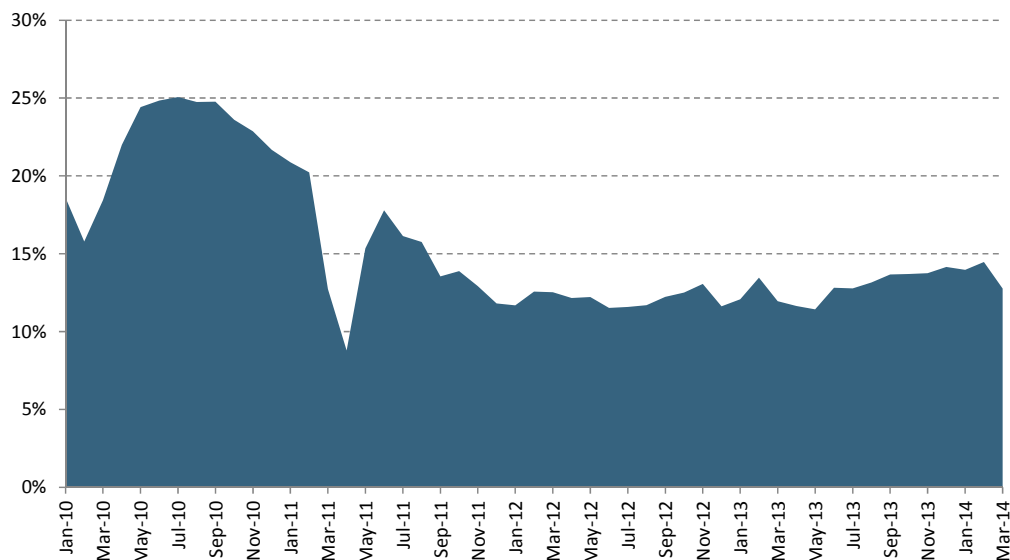
Payback math and return on invested capital for the different fuel types

	Gasoline	Diesel	Ethanol	Methanol	Compressed Natural Gas	Hydrogen fuel cell	Electric Vehicle
Gasoline gallons equivalent used (bn)	145.1	145.1	145.1	145.1	145.1	145.1	145.1
GGE cost per gallon	\$ 3.33	\$ 2.86	\$ 3.10	\$ 2.76	\$ 2.20	\$ 1.87	\$ 0.85
Annual LV fuel expenditures	\$ 483	\$ 416	\$ 450	\$ 400	\$ 319	\$ 272	\$ 123
Annual savings (relative to gasoline)	NA	\$ 67	\$ 33	\$ 83	\$ 164	\$ 211	\$ 360
Consumer investment	NA	\$ 457	\$ 76	\$ 127	\$ 2,029	\$ 5,072	\$ 2,110
Payback (years)	NA	6.8	2.3	1.5	12.4	24.0	5.9
Return on invested capital (ROIC)		15%	43%	65%	8%	4%	17%

Source: Goldman Sachs Global Investment Research

An interesting live example of using ethanol as substitute for gasoline is Brazil where a large fleet of flex fuel vehicles allows the population to switch back and forth depending on which is cheapest. In Exhibit 31 we can see that E100 as percentage of total fuel consumption has varied between 25% and 10% over the last 3.5 years. Because the price of gasoline in Brazil is fixed by Petrobras, much of the variation comes from the price of sugar cane.

Exhibit 31: Flex fuel vehicles in Brazil lead to a much wider consumption of ethanol E100 as a % of fuel consumption



Source: UNICA

The fuel cost lifecycle

The other half of the payback calculation is the cost of the fuel. This is actually a more involved process to assess than one might at first expect, as actively quoted ethanol pricing exists for renewable ethanol only (e.g., corn-based not natural gas-based), methanol is available at wholesale but not at gas stations, and the availability of compressed hydrogen for FCVs is still in its infancy. As such we have sought to construct what natural gas based ethanol and methanol should cost at the pump, factoring in today's feedstock prices, returns on refining and transportation investments, and distribution and retailing margins. We have made similar adjustment for hydrogen.

The conclusion is that on a gallon of gas equivalent basis (GGE) ethanol and methanol offer attractive economics at \$3.10 and \$2.76, surpassing traditional gasoline and diesel. While the pure feedstock price for both of these fuels is even cheaper at \$0.91 on a GGE basis, they lose some ground given a less developed transportation infrastructure, and lower density so you have to transport more fuel to get the same equivalency of a gallon of gas. We note diesel screens attractively as well on a GGE basis given the energy density and efficient combustion of a diesel engine, but it does less well on payback given the relatively high incremental investment for the powertrain (we use \$1,800).

Among the non-liquid alternatives electric vehicles are by far the cheapest at \$0.85 on a gallon equivalent basis using national retail electricity prices. Fuel cells are also cheap to run at \$1.87, though as previously discussed this is not yet sufficient to offset the sizable additional powertrain premium of \$20k at today's prices.

Exhibit 32: Fuel costs by lifecycle stage on a GGE basis

		\$ cost per gallon equivalent						
		Gasoline	Diesel	Ethanol	Methanol	Compressed Natural Gas	Hydrogen fuel cell	Electric Vehicle
Well	Extraction	\$ 2.33	\$ 1.69	\$ 0.91	\$ 0.91	\$ 0.54	\$ 0.25	\$ 0.37
	Refining/conversion/ generation	\$ 0.40	\$ 0.43	\$ 1.25	\$ 0.73	\$ 0.15	\$ 0.41	\$ 0.09
	Transportation/pipeline	\$ 0.07	\$ 0.14	\$ 0.31	\$ 0.41	\$ 0.47	\$ 0.15	\$ 0.09
	Retail distribution	\$ 0.10	\$ 0.26	\$ 0.24	\$ 0.31	\$ 0.64	\$ 0.67	\$ 0.25
Wheels	Consumption	\$ 0.43	\$ 0.34	\$ 0.40	\$ 0.40	\$ 0.40	\$ 0.40	\$ 0.06
	TOTAL	\$ 3.33	\$ 2.86	\$ 3.10	\$ 2.76	\$ 2.20	\$ 1.87	\$ 0.85

Source: EIA, NRRI, consultants, Goldman Sachs Global Investment Research.

We estimate that electric vehicles are 4.0x more energy efficient on a BTU basis

Part of the reason for the strong performance of EVs from a variable cost perspective is the efficiency of the EV powertrain itself. In our side-by-side comparison in Exhibits 33-34, we break down the amount of BTUs of natural gas that are required to go one mile through the various stages of refining/generation/combustion of an ethanol ICE (internal combustion engine) and an electric vehicle.

Electric vehicles begin at a disadvantage with a higher percentage of energy losses at the power plant as natural gas is burned to generate electricity. Additionally, transmission losses, battery charging losses, and self-discharge of the battery over time further penalize electric vehicles. This means that only 40% of the original natural gas BTUs is actually used in the vehicle vs 60% for an ICE. However this is more than made up for by a much more energy efficient electric motor where 60% of the BTUs directly power the vehicle compared to 23% for an ICE given significant engine losses due to thermal loss (radiator), exhaust heat, combustion, pumping, and friction. Additionally, drivetrain losses and idling losses continue to mount against the efficiency of an ICE. At the end only 14% of the original BTUs are converted to mileage for an ICE vs 29% for an EV.

Exhibit 33: ICE engines lose a lot of ground with an inefficient combustion process

Internal combustion engine vehicle energy efficiency

Ethanol Internal Combustion Engine		
Beginning energy required	9,218 BTUs	
Ethanol conversion loss	3,687	Lose 40% in conversion process
Power to vehicle	5,531 BTUs	
Engine Losses	3,595	65% - 69% loss
Parasitic loss	221	4% - 6% loss
Idle loss	166	3% loss
Drivetrain loss	277	5% - 6% loss
Power to wheels	1,272 BTUs	Vehicle efficiency: 23.0%
Percentage of original BTUs	13.8%	

Source: US Dept. of Energy, Goldman Sachs Global Investment Research

Exhibit 34: Electricity generation requires more BTUs upfront but this is offset by electric motor efficiency

Electric vehicle energy efficiency

Electric Vehicles		
Beginning energy required	2,120 BTUs	
Conversion/Generation	1,024	kWh/BTU divided by plant efficiency factor
Power at generation	1,096	
Transmission	66	6% of generation
Power to wall	1,030 BTUs	
Battery charging	103	10% loss
Battery (self discharge)	93	10% loss, after battery charge loss
Power to vehicle	834 BTUs	
Motor efficiency	181	20% - 24% loss, after battery losses
Parasitic loss	33	4% loss, after battery losses
Power to wheels	620 BTUs	Vehicle efficiency: 60.2%
Percentage of original BTUs	29.2%	

Source: US Dept. of Energy, Goldman Sachs Global Investment Research

The emissions lifecycle

In addition to what makes sense from a cost perspective, emissions are a critical focus when it comes to transportation. Within the world of emissions carbon has become the principal focal point as unlike particulate matter it cannot be filtered out and needs to be

addressed though fuel economy. The United States uses both an MPG approach through CAFÉ and a parallel set of Green House Gas standards through the EPA. Most other countries express their standards in terms of grams of CO₂ per km. In many cases the notation “CO₂e” is used which indicates grams of total greenhouse gases are being taken into account including methane and nitrous oxide, not just carbon.

The data shown in Exhibit 35, sourced from Argonne National Laboratory, estimates the CO₂ impact of driving 1 Km on “well to wheels” or “full lifecycle” basis. This measures the CO₂ produced during the extraction/refining/transportation process –what we call “well-to-tank” and the CO₂ emitted during the engine combustion process – called “tank-to-wheel”. While ethanol and methanol create less CO₂ during the combustion process than gasoline, they generate more CO₂ in the “well-to-tank” part of the cycle leaving them about the same with gasoline. This is similar in other well to wheel studies completed by the European Commission Joint Research Centre.

What is positive for ethanol is that this carbon impact could be reduced by controlling methane leakage from older wellheads at the source as well as by moving refineries closer to natural gas fields to limit losses from processing and transportation. As shown in Exhibit 36, Argonne’s framework implies that nearly 40g of CO₂ per km comes from methane leakage, and reducing this could put ethanol and methanol meaningfully ahead of gasoline on a complete well to wheels basis.

Finally, not surprisingly hydrogen fuel cells and EVs score very well on CO₂ as they have no tank-to-wheel CO₂ just what is created in the process of generating electricity and hydrogen. This is another facet that underscores the long-term potential of EVs, in our view.

Exhibit 35: Ethanol well to wheel CO₂e emissions are similar to gasoline but could be materially improved by reducing methane leakage
Grams of CO₂e per km

		CO ₂ e grams per kilometer						
		Gasoline	Diesel	Ethanol	Methanol	Compressed Natural Gas	Hydrogen fuel cell	Electric Vehicle
Well	Extraction	9	9	24	24	48	22	13
	Refining/conversion/generation	51	39	60	60	13	158	155
	Transportation/pipeline	NA	NA	NA	NA	NA	NA	NA
	Retail distribution	NA	NA	NA	NA	NA	NA	NA
↓								
Wheels	Consumption	230	191	211	205	189	0	0
	TOTAL	289	240	295	289	250	180	168
	TOTAL adjusted for 3/4 reduction in CH ₄ leakage	289	240	266	260	233	180	168

Source: Argonne National Laboratory, Goldman Sachs Global Investment Research.

Exhibit 36: About 40 grams of CO₂ per km for ethanol/methanol comes from methane leakage and venting
Grams of CO₂e

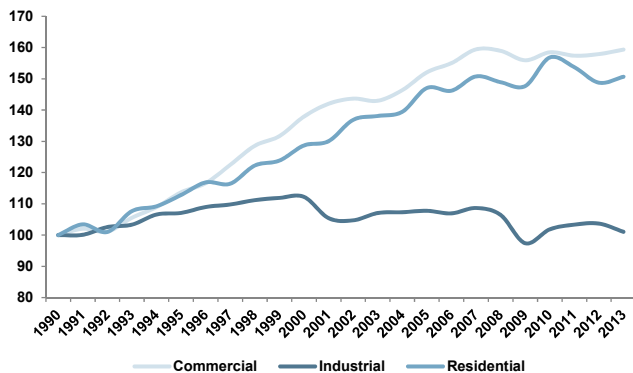
	Nat gas gCH ₄ /mmBtu	gCO ₂ e/ gal equiv			gCO ₂ e / Km		
		CNG	Ethanol	Methnaol	CNG	Ethanol	Methnaol
Recovery - Completion CH ₄ Venting	43	120	202	202	3	5	5
Recovery - Workover CH ₄ Venting	9	24	40	40	1	1	1
Recovery - Liquid Unloading CH ₄ Venting	10	29	48	48	1	1	1
Well Equipment - CH ₄ Venting and Leakage	59	166	278	278	4	7	7
Processing - CH ₄ Venting and Leakage	37	104	174	174	3	5	5
Trans and Storage - CH ₄ Venting and Leakage	87	245	411	411	6	11	11
Distribution - CH ₄ Venting and Leakage	71	198	333	333	5	9	9
Total	316	886	1,486	1,486	23	39	39

Source: Argonne National Laboratory, Goldman Sachs Global Investment Research

Policy focus 3: Exploiting scalable technologies to promote an environmentally sustainable generation outlook

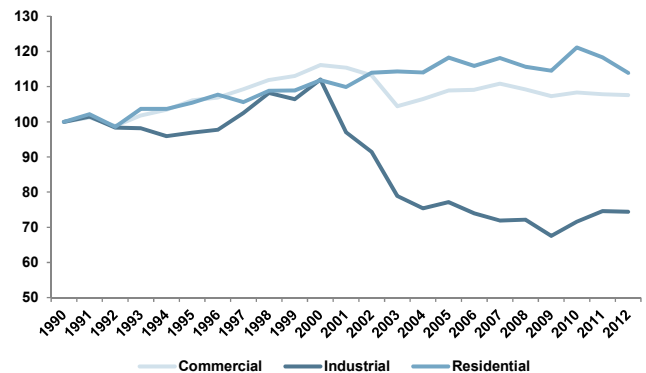
Electricity demand growth slowed in the last 10+ years and many expect slow growth to continue – partially due to energy efficiency, but also as demand from industrial customers moderated. We estimate – in line with what many utilities expect – roughly 0.6%-0.7% annual power demand growth, well below long-run historical levels of 1.5%-1.6% annually. The historical relationship or correlation between power demand growth and GDP growth, whereby every 1% change in GDP growth drove a 0.6% change in power demand, now appears unlikely to continue. We note, however, that energy efficiency is not the only factor driving changes in power demand in the United States; over the last 10-20 years, power demand growth levels from large industrial users slowed significantly, partially driven by efficiency, but also likely driven by a move of many heavy manufacturing intensive industries to locations outside of the United States. A change in policy – including policies that stimulate new manufacturing or new technologies like electric vehicles – could also reinvigorate electricity demand growth trends.

Exhibit 37: Electricity demand from industrial customers declined due to economic trends and efficiency gains
Power demand by customer class (Indexed)



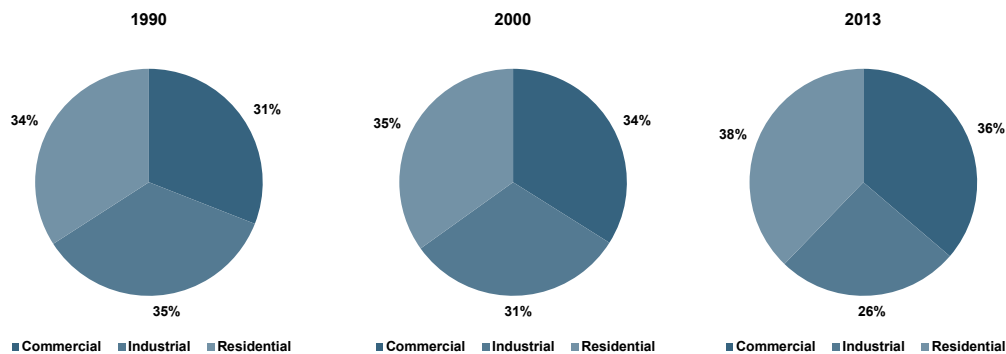
Source: EIA, Goldman Sachs Global Investment Research.

Exhibit 38: ...as usage per customer declined over the years
Usage per customer (Indexed)



Source: EIA, Goldman Sachs Global Investment Research.

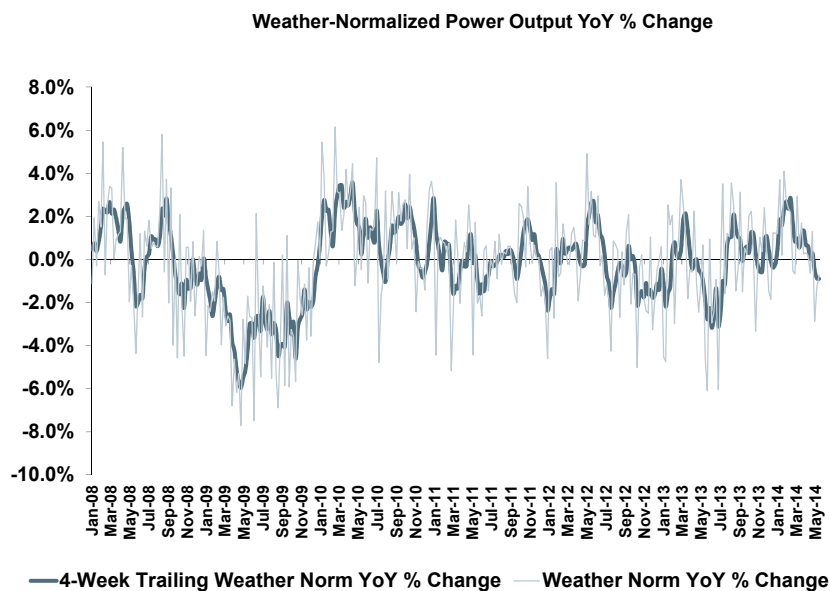
Exhibit 39: Industrial demand, relative to residential and commercial demand, consistently declined over the years
Power demand by customer class



Source: EIA, Goldman Sachs Global Investment Research.

Exhibit 40: We note that weather normalized demand growth may remain below long-run levels of 1.5%-1.7%, partially due to energy efficiency trends

Weather-normal power demand



Source: EIA, NOAA, Goldman Sachs Global Investment Research.

Understanding US power market dynamics is key as the US power market remains somewhat fragmented. Instead of one centralized power market structure, as seen in parts of Europe and South America, the US and the Canadian power markets remain a series of regional power markets, given different regulatory structures and geographic limits. Two structures generally exist in the United States:

- **Large parts of the Southeast, Southwest, the Northwest and parts of the Midwest continue to operate under traditional regulatory structures** – where the state regulator oversees the local utility that provides generation, transmission and distribution services to customers. Generation planning largely consists of integrated resource plans filed by these regulated utilities, with the utility either building new generation as needed or entering into long-term contracts for new generation supply from third parties. Costs incurred by the utility generally get “passed through” to customers, and the utility earns a regulated return on its assets or rate base.
- **In Texas, the Northeast and parts of the Midwest, state regulators and policy makers deregulated generation supply** over the last 10-15 years, while transmission and distribution service remains highly regulated. The local “monopoly” utility no longer provides generation; instead, in these markets, either the utility or its customers purchase generation from competitive suppliers that depend on multiple revenue sources (energy and capacity sales) to recover fixed, capital and operating costs.

Power plant development, like other infrastructure investments, occurs in cycles – although market design changes or state/federal policies often drive these cycles.

For example, from the late 1990s through 2005, the United States almost doubled the amount of gas-fired generation developed, largely as:

- 1) **Many states and regions deregulated their power markets** – and many utilities, seeking businesses or portfolios that offer higher returns than state regulated levels, built an abundance of gas fired generation, and

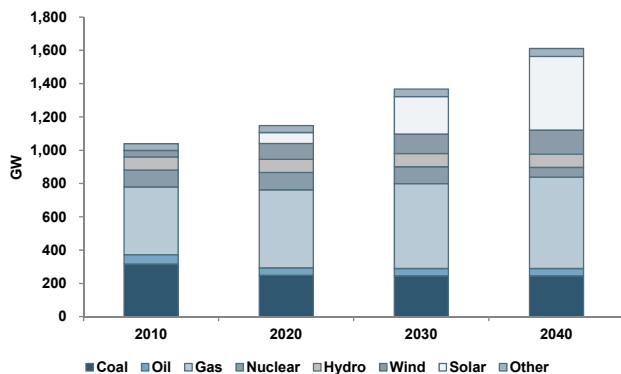
2) **Natural gas prices remained relatively low in this period**, making gas generation potentially more economic, but with the price increases beginning in 2004+, along with a significant over-supply of power generation in general, many of these investments suffered significant write-downs by non-regulated power companies adding new generation into a market already in surplus conditions.

Given current federal and state policies, as well as improving costs, renewables development growth may remain elevated. With many states actively pursuing renewables standards that mandate a specific amount of total generation or demand comes from non-conventional sources, combined with significant federal tax credits helping the economics of new renewables, the United States has and will likely still see a sizable increase in wind and solar generation. Tax-related benefits such as production tax credits or the investment tax credit make the levelized cost of electricity from renewable sources appear lower than otherwise would occur without these benefits, costs that are generally “socialized” across all federal tax paying entities or persons.

Our base case for US power generation capacity assumes significant coal retirements, partially offset by growth in natural gas and renewable generation capacity. We forecast (1) roughly 20%-25% of coal generation retires due largely to environmental rules on a variety of pollutants, (2) renewables development, primarily wind and solar, continues to ramp significantly through 2020-2025 driven by state-level renewable portfolio standards (RPS), (3) nuclear development remains modest and may even decline as plants age (reaching the end of their 60 year intended lives) and as licenses expire in the 2030-2040 period, and (4) development of new gas generation will continue, albeit at a modest pace, partially driven by local congestion and partially to replace retiring coal units. We expect modest capital allocation to new coal generation (unless technologies quickly advance to make carbon capture and sequestration more economically viable); recent trends at several large utilities imply this still remains a technical challenge. As noted above, our base case assumes relatively low, compared to history, growth in power demand.

Exhibit 41: Environmental regulations and low power prices will drive a reduction in coal-fired generation in the US

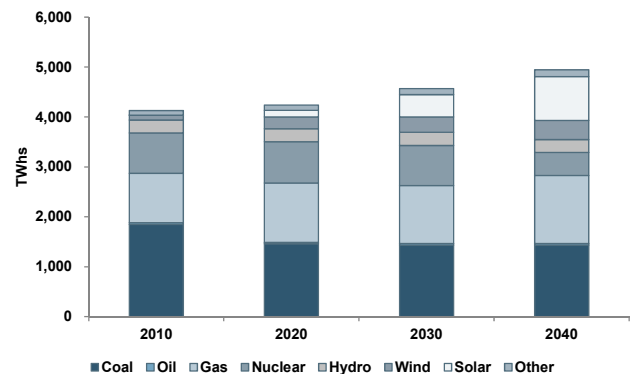
Capacity by type in GW



Source: EIA, Goldman Sachs Global Investment Research.

Exhibit 42:and both state and federal policies will drive growth in renewables, along with gas generation

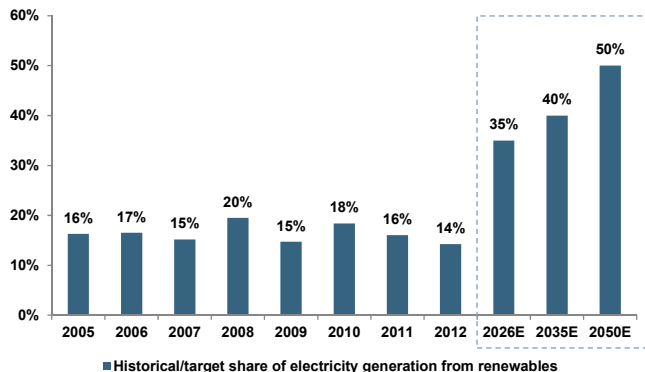
Generation (TWhs) by fuel type



Source: EIA, Goldman Sachs Global Investment Research.

Exhibit 43: Policies and government initiatives exist to increase renewables in Mexico...

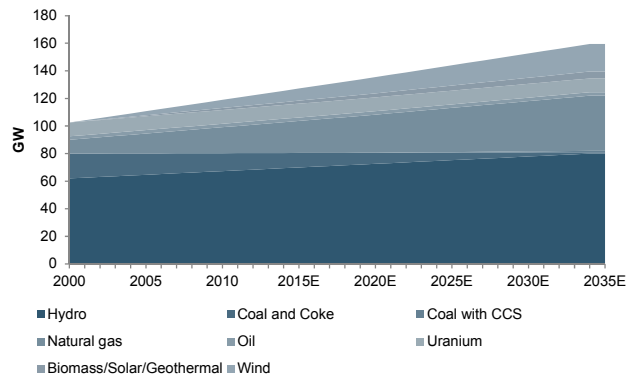
Historical/target renewable generation as a % of total generation



Source: EIA, REN21, Goldman Sachs Global Investment Research.

Exhibit 44: ...and to drive substantial renewable expansion in Canada as well

Historical and expected capacity by fuel type



Source: NEB Canada, Goldman Sachs Global Investment Research.

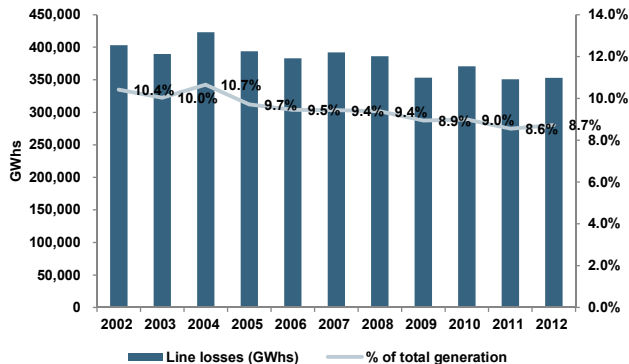
For policymakers seeking continued growth in renewables, we note natural gas fired generation must accompany this renewable expansion.

Intermittency remains a key challenge impacting renewables, as these sources still run at capacity factors or utilization rates well below those of conventional forms of power generation. Unlike nuclear or coal generation, natural gas power plants can ramp up quickly, which is extremely important given the potential for wind or solar capacity factors to decline rapidly, intra-day, as their respective resources decline. In other words, when levels of sunlight or wind decline, the grid will need conventional, fast-starting power generation. With nuclear generation still expensive to build and coal generation facing environmental constraints, natural gas generation will likely emerge as (1) more of a base-load resource and (2) a key tool, for those seeking more renewable growth, to help balance intermittency of renewables.

Other challenges exist for increasing the scale of various forms of new power generation.

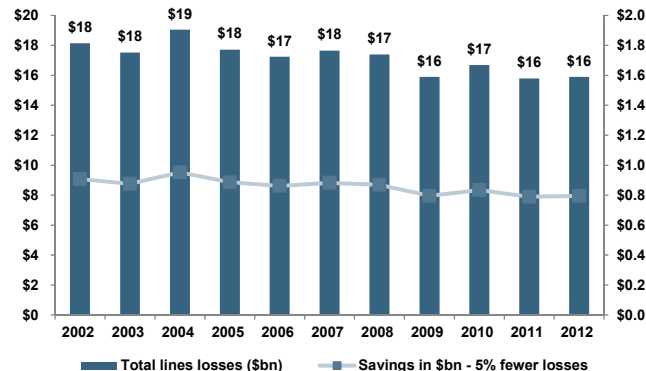
Coal-fired power plants face multiple challenges, until carbon capture and sequestration becomes a low cost, low emissions technology, both in terms of environmental regulations in many markets and in overall economic cost, especially when natural gas prices remain at or below \$6/MMBtu. Renewables, as detailed above, face intermittency issues, making them difficult to consider as base-load resources unless the centralized storage of electricity occurs at a relatively low cost. Nuclear generation construction costs remain elevated, and cost over-runs often occur. Finally, we note both nuclear and renewables capacity requires sizable transmission investment, as utilities generally locate these plants in highly rural areas, either due to the resource location (i.e., in the California desert) or for environmental/safety reasons (nuclear).

Exhibit 45: Transmission & distribution inefficiencies cause losses of 8 - 9% of total generation...
Line losses, in GWh (lhs); in % of total generation (rhs)



Source: EIA.

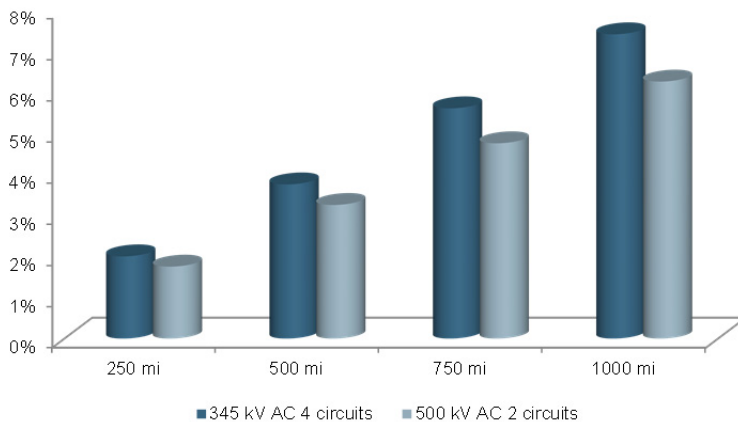
Exhibit 46: ... implying larger transmission-related costs associated with remote generation sources – such as nuclear or renewables
Line losses, \$bn (lhs); Savings from reduced line losses, \$bn (rhs)



Source: EIA, Goldman Sachs Global Investment Research.

While gas generating plants often get built near urban or suburban locations, renewables and nuclear development occurs in more remote locations, driving higher transmission costs and greater potential line losses. We note utilities develop gas-fired capacity in a host of areas – urban, suburban and rural – as seen with recent new plants built in urban environments such as the New York City area, Atlanta, and the Los Angeles area. However, due to resource availability, size and even safety concern reasons, utilities generally build renewables and nuclear plants in more remote locations, driving the need for incremental long haul transmission, which increases cost and line losses (MWhs “lost” as they travel the transmission or distribution infrastructure before reaching customer locations).

Exhibit 47: Increased transmissions needs due to the location of plants relative to population centers can lead to higher costs and more line losses
Estimated line losses from new 500 MW transmission lines (AC), in %



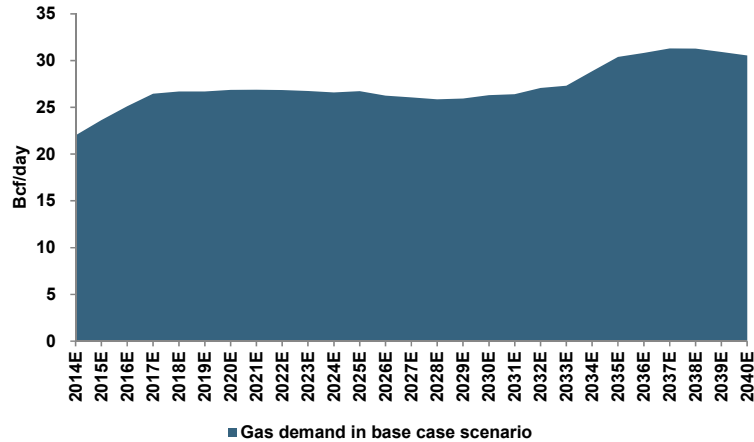
Source: Goldman Sachs Global Investment Research, Clean Line Energy.

We assume natural gas demand from the power sector grows by 2%-3% annually – but recognize a host of scenarios exist that could drive this higher. Our base case

forecast for natural gas assumes gas plants, which currently deliver 900-950 TWh per year, will increase 40%-45% over the next 25 years. As detailed in the exhibits below, a slow-down in the development of renewable capacity – especially in solar – or a dramatic increase in the level of coal plant retirements could drive usage of gas-fired generation up significantly, from 32-34 Bcf/d in 2040 in our base case to nearly 42-44 Bcf/d in more bullish scenarios for natural gas demand coming from the power sector.

Exhibit 48: Multiple demand, policy, environmental and cost factors will drive an increase in natural gas demand coming from the US power sector

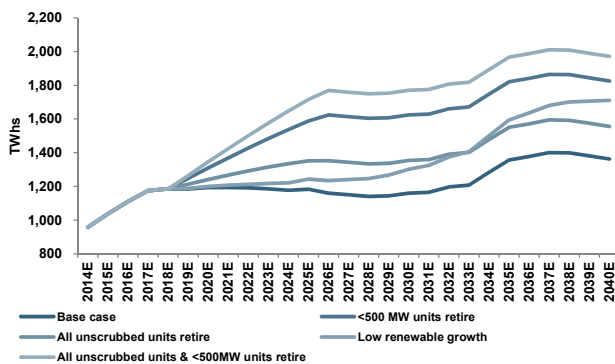
Demand for natural gas from the US power sector, in Bcf/d terms



Source: Goldman Sachs Global Investment Research.

Exhibit 49: Increased coal retirements or lower renewable growth may drive gas generation higher

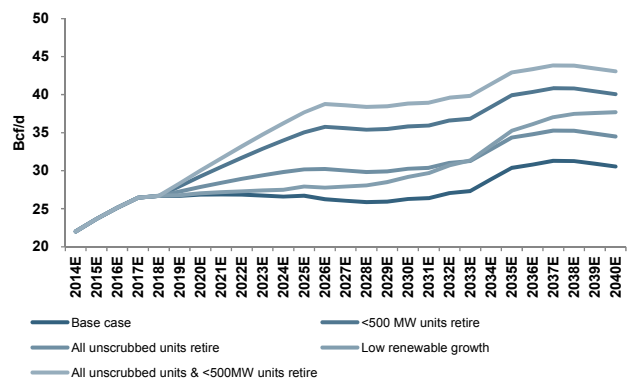
Gas generation levels in various scenarios



Source: SNL Energy, Goldman Sachs Global Investment Research.

Exhibit 50: ...implying potential upside in natural gas demand from the US power sector

Implied gas demand in various scenarios

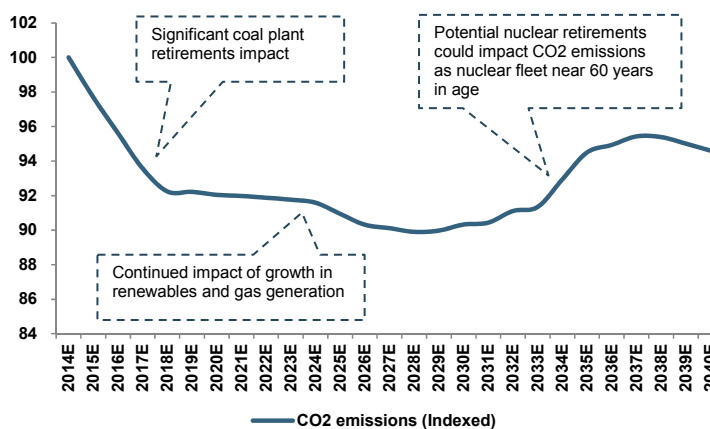


Source: SNL Energy, Goldman Sachs Global Investment Research.

Coal plant retirements will lead to a reduction in emissions over the near term – but emissions may increase later if nuclear development does not accelerate. All forms of fossil fuel generation emit CO₂, but on average, natural gas power plants emit about 40% of the rate of a typical pulverized coal facility. Given sizable coal plant retirements announced or coming in the next 3-5 years, we expect CO₂ emissions to decline by almost 10% in the near term before incorporating the impact of carbon regulations into our views and despite an increase in natural gas fired generation. The United States faces another

policy and economic challenge in future years though as the nuclear fleet ages and many plants reach 60+ years old, the length of their original licenses. Nuclear retirements would, as highlighted in our base case, lead to increased generation by natural gas plants and an increase in emissions as well.

Exhibit 51: We estimate CO2 emissions will decline in the near term as coal plant retirements – but an aging nuclear fleet presents a risk to emissions levels longer term
CO2 emissions forecast, indexed (2014-2040)



Source: Goldman Sachs Global Investment Research.

A rapid or almost overnight shift in the automotive fleet to a fleet comprised largely of electric vehicles would create a sizable increase in power demand. Currently, the US power sector maintains a surplus of supply and if electric vehicles gain share over a gradual, extended period, our base case forecast implies the United States would maintain enough power generation capacity to meet this demand. However, to highlight the potential impact of a dramatic and rapid penetration of electric vehicles, we assessed the amount of new power generation capacity and the cost of this capacity. This assumes the vehicle fleet changes in just a short period – a few years – and that the United States would need to add significant power generation quickly to meet this demand, an incremental 20%-25% versus our 2013 power demand forecast. High-level assumptions include (1) nuclear generation remains expensive to build, but operates at high utilization rates or capacity factors, (2) natural gas plants remain relatively inexpensive to build, but depend on gas prices remaining below certain levels to stay “economic”, and (3) construction costs for wind and solar plants stay expensive relative to natural gas units (still receiving subsidies or other public policies for the near/medium term) and run at lower capacity factors. Below, we summarize four scenarios to show the costs of building new generation to supply the US automotive fleet, assuming this fleet converts entirely to electric vehicles in a very short timeframe:

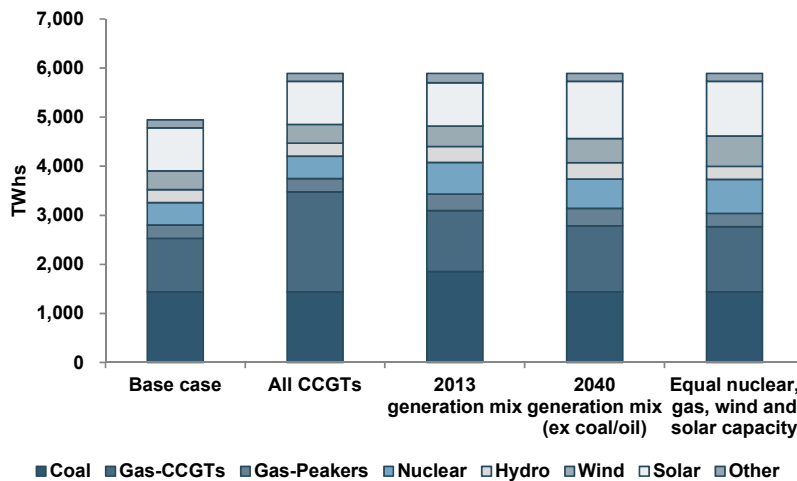
- 1) **The lowest cost option implies development of only new gas-fired generation capacity to meet this incremental demand**, leading to a sizable ramp in new generation of natural gas combined cycle plants or CCGTs, generation that costs less than other forms on an installed dollar per kW basis. This scenario assumes the greatest impact on US natural gas demand from the power sector, and relies significantly on continued low-cost natural gas resources, but also implies the lowest capital spending required.
- 2) **Another scenario assumes the US power generation supply mix remains the same as 2012-2013 levels**, implying development of a mix of new renewables, coal, natural gas, nuclear and other sources, and is a scenario that incorporates significant

capital to build new nuclear, coal and renewables generation, plants that cost, on a per kW basis, roughly 2x-4x the typical new gas power plant.

- 3) **A third scenario, one with expenditures near \$750bn, takes our base case 2040 forecast** – excluding the impact of electric vehicles – and assumes this becomes the “mix” of new generation developed to meet this incremental demand.
- 4) **A final scenario – with costs of almost \$700bn – that assumes an equal mix of new gas, nuclear and renewable resources is developed** to meet this demand from electric vehicles.

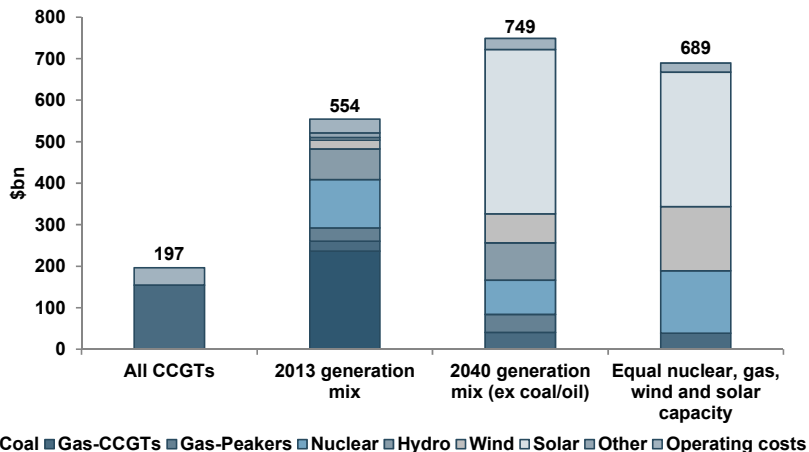
Exhibit 52: Our hypothetical analysis – where the entire automotive fleet converts to electric vehicles – shows that gas-fired generation at most would provide roughly 40% of total power generation

Power generation levels in scenarios assuming full EV penetration of the automotive fleet



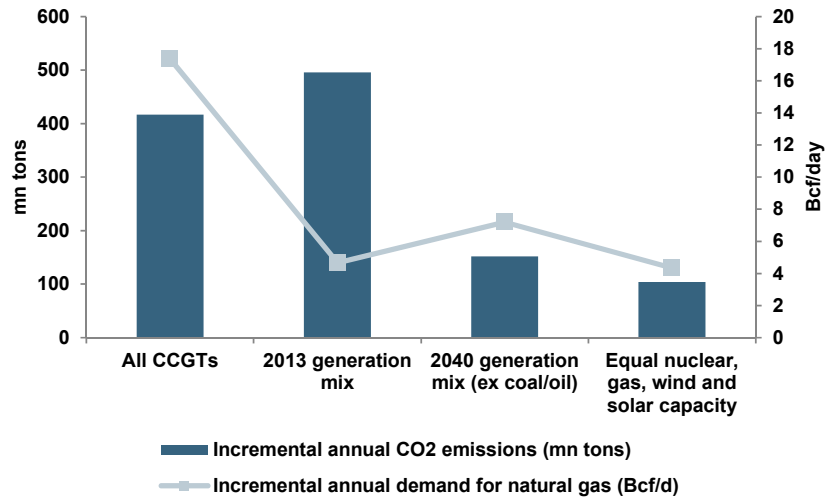
Source: EIA, SNL Energy, Goldman Sachs Global Investment Research.

Exhibit 53: Assuming natural gas prices stay near \$5-\$6/MMBtu, natural gas fired generation emerges as the lowest cost option to meet demand from electric vehicles
 Generation capital spending estimates, \$bn



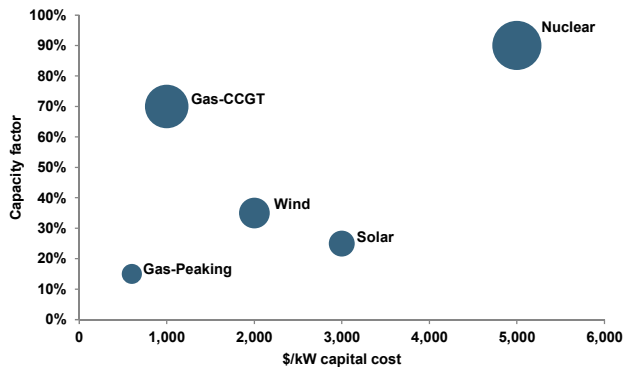
Source: Goldman Sachs Global Investment Research.

Exhibit 54: ...but also leads to higher emissions and increased use of natural gas
 CO2 emissions and implied incremental natural gas demand (on a Bcf/d basis)



Source: Goldman Sachs Global Investment Research.

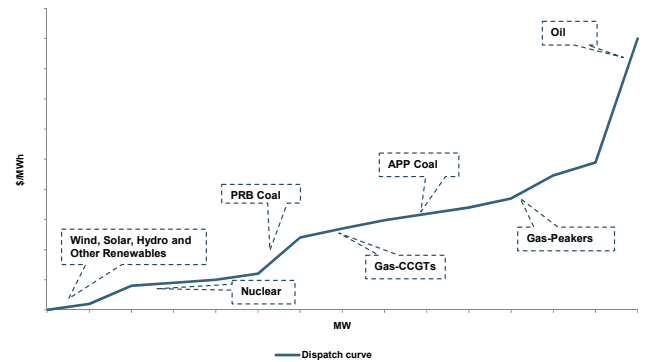
Exhibit 55: Despite higher fuel costs, the lower construction costs and higher capacity factors...
 Capacity factors and \$/kW capital costs by fuel type



*Size of the bubble represents relative generation levels on identical plant capacity

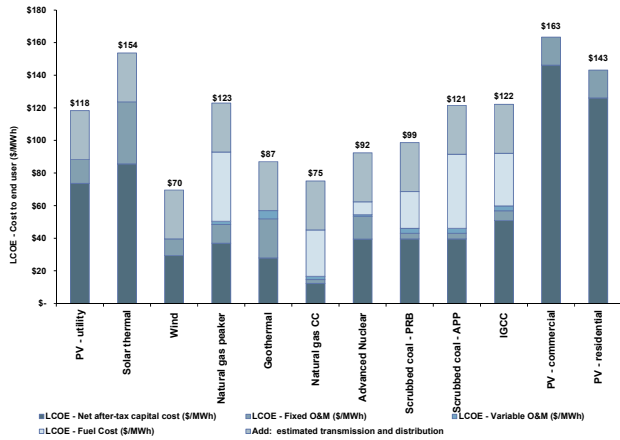
Source: Goldman Sachs Global Investment Research.

Exhibit 56: ...makes new natural gas power plants cost competitive when the US needs new supply
 Variable/fuel costs of power generation in the US



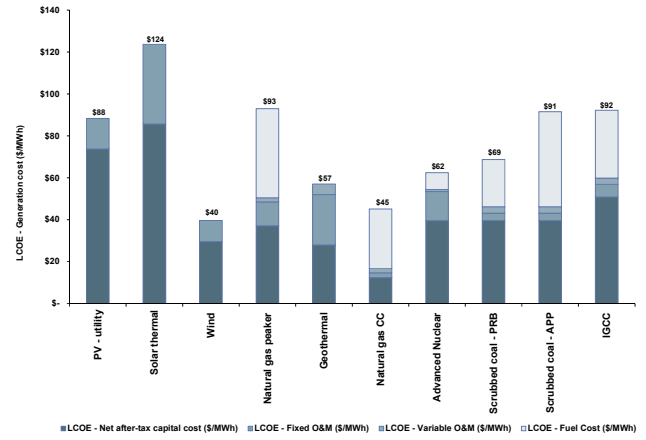
Source: Goldman Sachs Global Investment Research.

Exhibit 57: ...and despite fuel costs, remain one of the lower cost options on an "all-in" basis...
Levelized cost of electricity (\$/MWh)



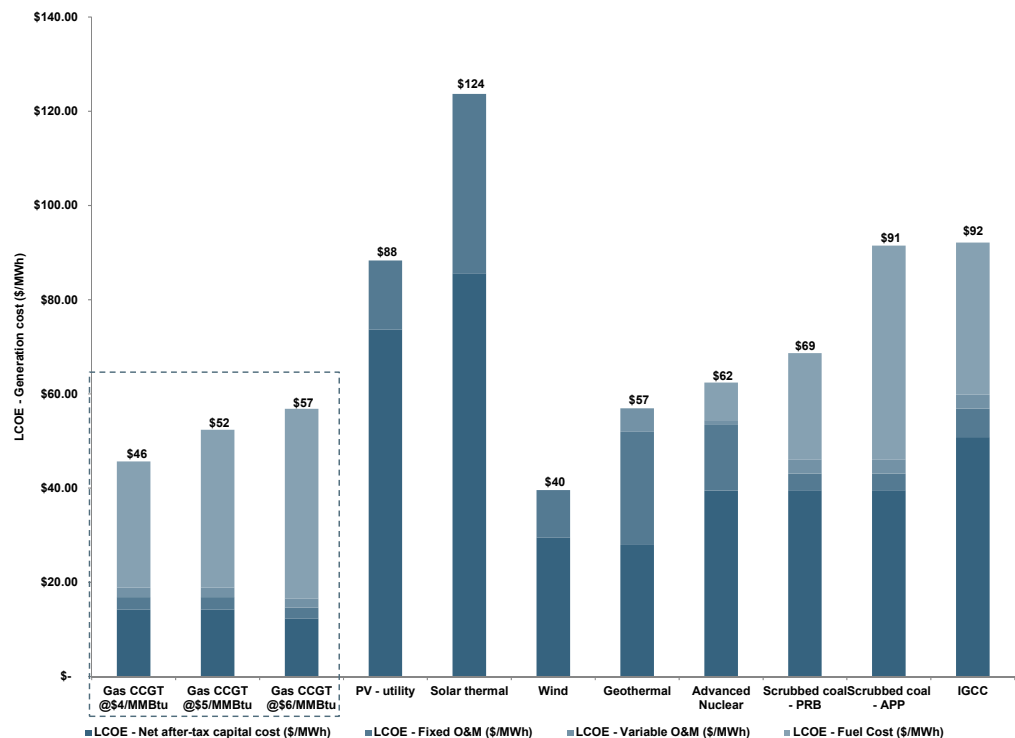
Source: Goldman Sachs Global Investment Research.

Exhibit 58: ...and especially when looking at just the costs of generation, excluding transmission/distribution expenses
Levelized cost of electricity (\$/MWh)



Source: Goldman Sachs Global Investment Research.

Exhibit 59:and even at higher natural gas prices, up to \$6/MMBtu, new combined cycle plants appear mostly economic versus other forms of new power generation capacity
Levelized cost of electricity (\$/MWh) – scenario analysis at natural gas prices of \$4-\$6/MMBtu



Source: Goldman Sachs Global Investment Research.

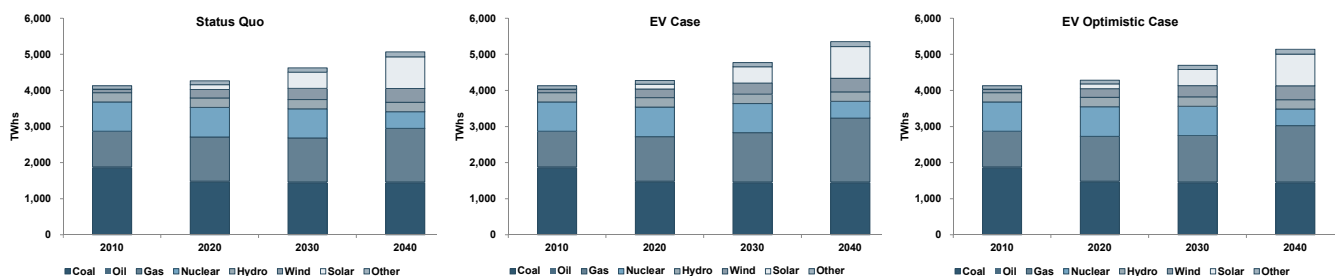
A more likely scenario for electric vehicles, a gradual shift over 30+ years in the US automotive fleet, would stimulate increased natural gas demand. Above, we highlighted scenarios of the impact on power generation capacity, natural gas demand and emissions, if the US automotive fleet quickly converted to use solely electric vehicles. A

more realistic approach assumes a gradual penetration of electric vehicles, whereby over a long time period (30+ years), electric vehicles capture some share of the automotive market, albeit not one hundred percent of the vehicle market.

- **We analyzed three scenarios of potential electric vehicle penetration and the resultant impact on the power sector.** These scenarios include (1) status quo policies and penetration of electric vehicles that reach 27-28m by 2040, (2) a slightly more optimistic case, where over 35m electric vehicles exist in 2040 and (3) a more bullish outlook, with over 92m electric vehicles in service by then.
- **Incremental gas generation can help meet this demand for electric vehicles.** Based on our supply/demand analysis of the US power market, we believe the new capacity our base case forecast includes could meet gradual increases in electric vehicle demand for power, but could add 8-10 Bcf/d in natural gas demand from the US power sector. We also assume that this incremental natural gas generation would lead (relative to our base case) to a minor increase in CO2 emissions from the power sector, albeit an increase of only 5%-10%.

Exhibit 60: Additional power generation from gas-fired capacity – along with expected growth in renewables – would provide the power supply needed to support a gradual ramp in electric vehicles

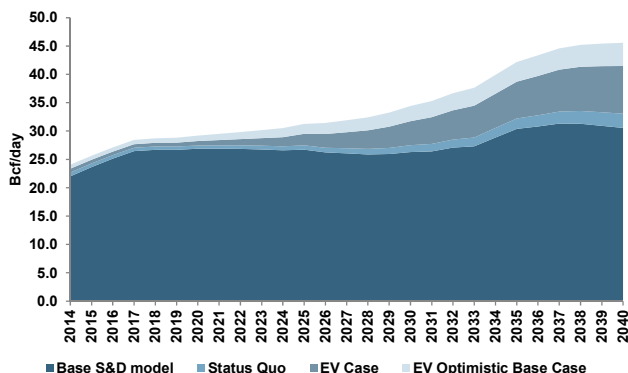
Power generation in MWhs by fuel type under different electric vehicle penetration scenarios



Source: EIA, SNL Energy, Goldman Sachs Global Investment Research.

Exhibit 61: By 2040, we forecast 8 bcf/day of incremental demand in the most bullish EV scenario...

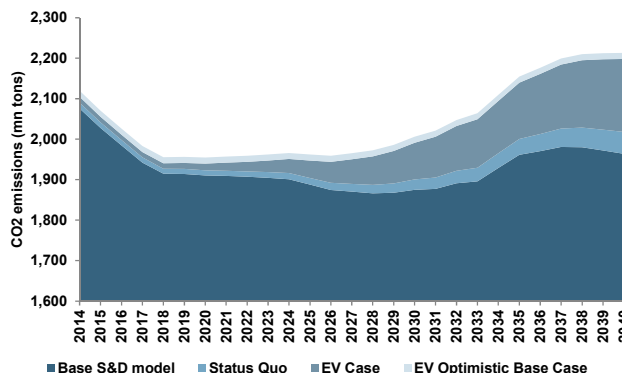
Estimated incremental natural gas demand due to electric vehicle penetration (in Bcf/d terms)



Source: EIA, SNL Energy, Goldman Sachs Global Investment Research.

Exhibit 62: ... and expect CO2 emissions to increase by 180mn tons

CO2 emissions, base case and electric vehicle scenarios



Source: EIA, SNL Energy, Goldman Sachs Global Investment Research.

Raw material scalability: An EV upside case would require significant production increases but reserves look adequate

With an abundance of reserves for key inputs at current battery technology, we believe that the entire US vehicle population could be converted to electric vehicles. That said, near-term production of certain key elements would have to accelerate meaningfully in order to prevent them from being a limiting factor.

The most limiting of the current inputs are lithium, cobalt, and graphite where a 100% move to EVs by the US market would require a 254%, 120% and 72% increase in global production. Because even our upside case has EVs accounting for 40% of sales by 2050 we believe global production should have time to adapt.

Therefore, what ultimately really matters is reserves, and here lithium and graphite look plentiful with a 100% conversion of the US vehicle stock representing 8% and 11% of proven global reserves, respectively. For cobalt, current production capacity is in better shape than lithium, but over the long term, with current battery technologies, cobalt would become a limiting factor with the US fleet likely requiring 33% the world's proven reserves.

That said, it is important to note that this constraint is likely multiple decades away and as cell/chemistry technology advances, electric vehicles producers will target those new technologies that minimize cobalt consumption—not only because of its more limited supply but also to reduce reliance on raw material sourcing from politically unstable environments (50% of world reserves and production are located in the Democratic Republic of Congo).

In our most bullish scenario, we estimate that annual lithium, cobalt, and graphite production would need to increase from 2013 levels by 144%, 68%, and 41% by 2050—large increases, but enough runway that capacity/production should not be an issue.

Exhibit 63: Raw material production would need to rise materially in a bullish EV scenario, but long-run reserves appear satisfactory

Battery component requirements, annual production, and reserves

Battery Component	Per Vehicle Amount		Vehicle Sales (mn)		Tons Required		2013 Global Production (tons)	US Fleet % of Production
	Lbs.	Tons	US	Global	US	Global		
Lithium	14	0.01	16.0	85.1	101,605	540,216	40,000	254.0%
Cobalt	20	0.01	16.0	85.1	143,999	765,617	120,000	120.0%
Graphite	118	0.05	16.0	85.1	855,991	4,551,166	1,190,000	71.9%
Aluminum	402	0.18	16.0	85.1	2,915,924	15,503,495	50,097,105	5.8%
Copper	124	0.06	16.0	85.1	901,507	4,793,167	17,900,000	5.0%
Nickel	38	0.02	16.0	85.1	275,302	1,463,734	2,490,000	11.1%

Battery Component	Per Vehicle Amount		Vehicle Population (mn)		Tons Required		Reserves (tons)	US Fleet as % of Reserves
	Lbs.	Tons	US	Global	US	Global		
Lithium	14	0.01	256.0	1,067.2	1,625,675	6,777,261	20,000,000	8%
Cobalt	20	0.01	256.0	1,067.2	2,303,976	9,605,025	7,200,000	32%
Graphite	118	0.05	256.0	1,067.2	13,695,859	57,096,540	130,000,000	11%
Aluminum	402	0.18	256.0	1,067.2	46,654,787	194,498,704	7,000,000,000	1%
Copper	124	0.06	256.0	1,067.2	14,424,115	60,132,559	690,000,000	2%
Nickel	38	0.02	256.0	1,067.2	4,404,827	18,363,243	74,000,000	6%

Note: battery component list is not exhaustive

Source: USGS, IHS, Goldman Sachs Global Investment Research

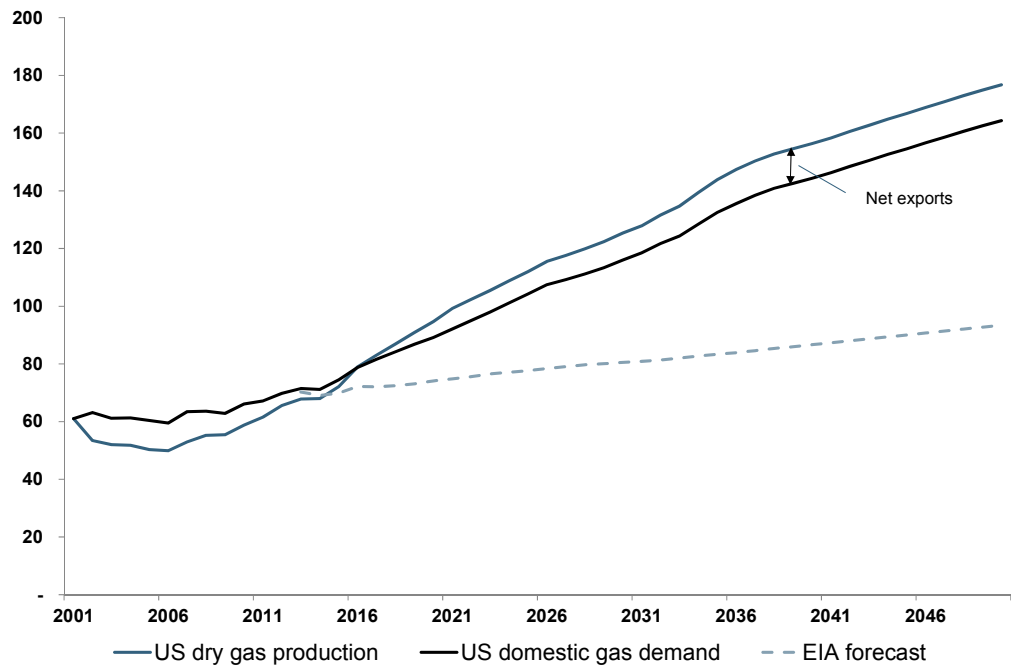
Potential impact of demand-side policy reform: United States

Meaningful economic opportunity to stimulate domestic gas usage

We see opportunity for commitment to domestic natural gas development to add 0.8 percentage points on average to US GDP growth per annum through to 2050 (peaking at 1% in late 2020/early 2030), though we do not believe this is on track at present. We believe identified resources for US natural gas can support peak demand that is more than double the current market, which can be accomplished if there are commitments to domestic industrial expansion, the use of gas and electricity as vehicle fuels and a further expansion of gas in the generation mix. As we argue in more detail below, these commitments raise the potential for North America not only to benefit economically from cheaper, more readily accessible energy, but also make significant progress toward achieving a more environmentally sustainable energy mix. Without structural commitment to natural gas demand, however, the abundant US shale gas resources would likely find an outlet in the form of LNG exports that could ultimately be limited by demand in the global market which we believe would lead to a lower GDP benefit. To successfully develop domestic gas demand over the longer term, business and government leaders need to work together to solidify the confidence that is required to attract capital over the next 30 years.

Exhibit 64: We see potential for much greater gas demand vs. EIA forecast

GS estimated maximum potential gas demand (including net exports) vs. EIA forecast, Bcf/d



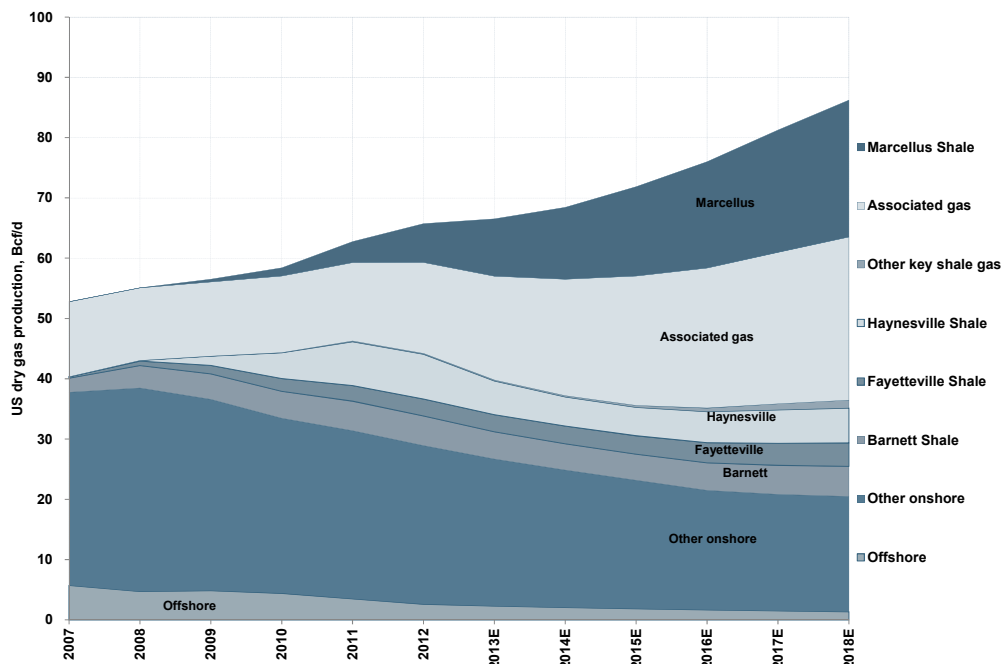
Source: EIA, Goldman Sachs Global Investment Research.

Shale resource has transformed the US natural gas supply landscape

US natural gas producers have gravitated towards developing shale because of: (1) shale's more favorable position on the cost curve vs. conventional gas drilling (we view shale play breakevens between \$4.00-\$5.00/MMBtu for shale plays vs. \$5.50+/MMBtu to meaningfully grow conventional resource; (2) technological improvements in horizontal drilling and

hydraulic fracture stimulation; and (3) greater capital availability partly as the repeatable “manufacturing” nature of shale drilling reduces expected volatility of well performance and partly due to lower interest rates. As a result, production from identified shale plays has risen to 40% of total US natural gas production in 2013 from just 5% in 2007. Regionally, the initial wave of growth came from the Barnett Shale (Texas) and Haynesville Shale (Louisiana/Texas) in 2008-11 with Henry Hub natural gas in the \$4.00-\$4.50/MMBtu range. More recently the growth has come from Marcellus Shale (PA/WV) and oil shale wells that produce associated gas – both are lower-cost sources of supply.

Exhibit 65: Identified shale plays represent 40% of US gas production; Marcellus Shale and gas from oil wells likely to support demand growth in next five years
 US dry gas production by basin in Bcf/d, 2007-18E



Source: EIA, IHS, Goldman Sachs Global Investment Research.

After a decade delineating and growing supply, the United States should see uplift in demand through the end of the decade. We divide up the US shale gas transformation into three five-year stages:

- **The discovery stage (2004-08).** This began with the commercial viability of horizontal shale drilling in the Barnett Shale and ended when shale production growth in aggregate became material to overall US natural gas production.
- **The supply response stage (2009-13).** Producers saw meaningful efficiency gains that further lowered shale’s position on the cost curve. Producers were forced to drill to hold acreage that inflated growth temporarily. Most importantly, there was little secular demand response because of both a lack of confidence in sustainability of shale production growth and time lag to bring new gas-intensive projects online. As a result, natural gas prices fell secularly due to a lower cost structure and cyclically to stimulate greater demand at the expense of coal.
- **The demand response stage (2014-18).** We see a material increase in gas demand that is less elastic to gas prices. We expect this to come from coal plant retirements,

LNG exports and industrial expansion. The coal plant retirements are driven by mercury/air toxics emissions regulations, and are largely concentrated in this decade.

Despite reaching the time for a demand response, the potential for shale gas supply in the United States to ramp up if needed is considerable. In such a demand-constrained environment, we believe that policy is most effective in addressing those constraints. To understand how the US economy can best manage these demand constraints, we approach the issue in two steps: (i) we estimate where the maximum potential opportunity for demand lies across the US generation, transport, industrial and LNG sectors (in the absence of policy constraints); (ii) we estimate what US gas prices would incentivize supply to meet these demand needs going forward.

To be clear, we present three possible scenarios for demand going forward: (i) a **“base case”**, in which policy does not change, and demand is only able to grow slowly; (ii) a **“max potential case”**, in which policy and uncertainty constraints are fully resolved and demand is able to grow at its full potential; and (iii) a **“target case”**, which lies in between cases (i) and (ii) and which we believe represents a realistic upside target for policymakers and business leaders to aim for.

Time to focus on the next three decades

Available resources, “domestic-vs.-export” strategy and confidence in environmental impact will define the future

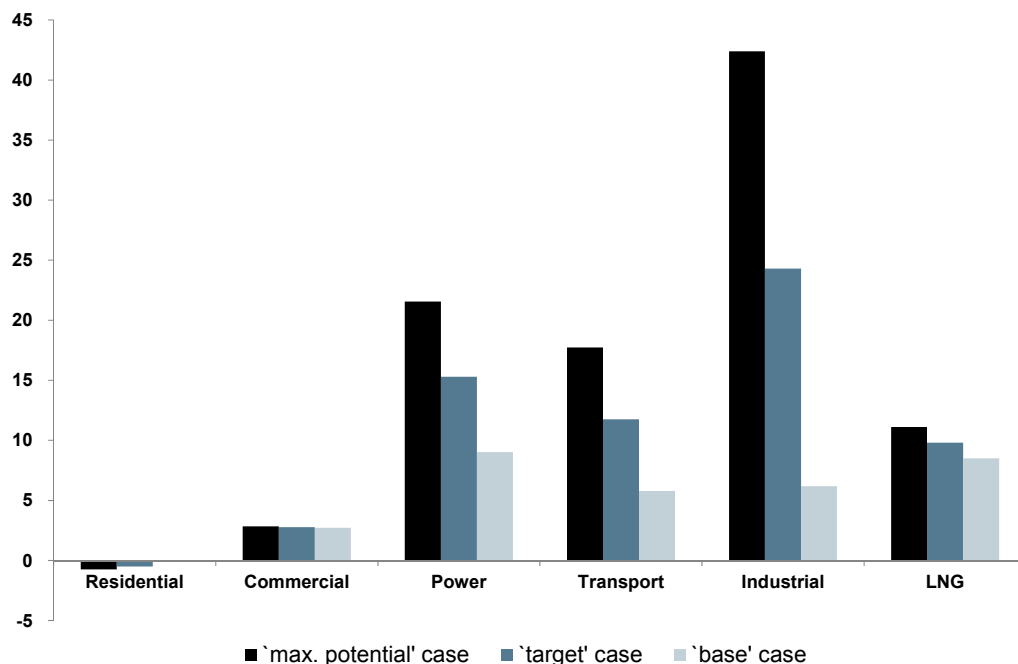
While we see some temporary support for demand in the coming years, it is important to emphasize that the United States has far greater potential to benefit economically and environmentally from its shale endowment. Given the long lead times for industrial, generation and transportation projects, we believe decisions made in the next few years will shape the level of natural gas consumption for the next decade. Decision making by political and business leaders is likely to center around confidence in three key factors: (1) available gas resources; (2) whether North America should pursue a domestic consumption vs. export path; and (3) resulting environmental impact. As highlighted below, we believe a domestic-focused natural gas strategy would provide greater benefits for US GDP growth and would allow for a greater use of relatively cheap, reliable US gas resources than an export-focused strategy. A shift towards natural gas from oil for vehicle fuel would likely reduce the impact to consumers of lifting the ban on US oil exports.

Demand: We see opportunity for almost 110 Bcf/d of domestic demand growth to 177 Bcf/d by 2050. Under our max potential scenario, in which a coordinated effort between business and political leaders provides greater confidence to stimulate downstream energy investment, we believe the United States would have the potential to significantly increase its consumption of natural gas by almost 110 Bcf/d by 2050. In particular, we see the potential opportunities for domestic natural gas demand spread across the following sectors:

- **Generation (+22 Bcf/d).** We estimate that if all unscrubbed coal-fired capacity would be phased out, natural gas-fired power generation would grow by 22 Bcf/d (2013 was 22 Bcf/d). At the same time, we see a large environmental potential from a heavy substitution towards renewables, whose importance in the generation mix rise from about 6% in 2013 to 28% by 2040 (compared to gas, whose share moves from about 23% to 40% over the same period). Natural gas plays two important roles in a successful environmental power strategy. First, it provides the bridge away from coal toward cleaner renewables – gas is more able to respond in the short term to coal retirements (for example, by increasing utilization at current facilities). But second, it is an important complement to renewables, able to respond at short notice to the intermittency of renewables generation.

- Industrial (+42 Bcf/d).** Despite years of decline in energy-intensive manufacturing in the US since 2003, which has seen the Middle East and Asia outbuild the United States by a factor of 15-to-1 in ethylene capacity in the last four years, we believe that the shale revolution provides an opportunity to reverse this trend. Given the cost advantage the United States now enjoys on petrochemical feedstock, the manufacturing opportunity is clearly large and has been since the shale revolution took off in 2010. However, we emphasize that achieving this target growth of 1.1 Bcf/d per year through to 2050 requires more than just favorable economics, as a host of uncertainties around continued availability of cheap feedstocks and sourcing skilled labor need to be resolved to encourage the relatively long-term, large greenfield investments. Indeed, the EIA projects average industrial demand growth of only 0.2 Bcf/d per year through to 2040 in its 2014 Annual Energy Outlook.
- Transportation (+18 Bcf/d).** We see the greatest potential for natural gas to revolutionize the US auto industry. In our “max. potential” scenario, ethanol-fueled vehicles increase to take up a 40% market share by 2050 (from only 2% now), electric vehicles expand to become 15% of the market, and gasoline serves only 40% of vehicles (from 95% today). We believe this would create 18 Bcf/d of incremental gas demand, primarily to provide natural gas-based ethanol (which can be manufactured at a lower cost than bioethanol). We estimate that such a change could save households up to 15% by 2030 on their transportation bills, as natural gas-based ethanol and electric power can be supplied more cheaply than gasoline. However, we emphasize that the timing of impact would necessarily be more gradual than on the generation or industrial sides, given the long replacement cycle for vehicles. Indeed, our “max. potential” scenario assumes that ethanol reaches about 5% market share only by 2025.

Exhibit 66: Meaningful gas growth potential from power, transport and industrial sectors
Demand growth potential in 2014-50 by key segments, Bcf/d



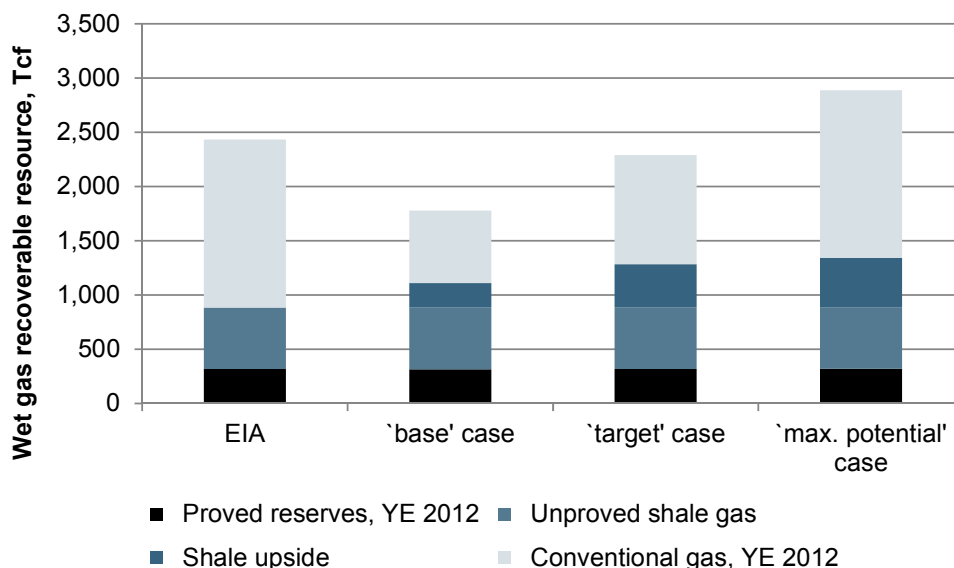
Source: Goldman Sachs Global Investment Research.

US natural gas resources are capable of supporting much greater demand growth

In its June 2013 report on technically recoverable shale oil and shale gas resources, the EIA identifies 2,431 Tcf of technically recoverable wet gas resource. This represents 100 years of production at 2013 levels. We believe this can support peak production that is more than double 2013 levels. Additionally, we believe there may be upside to identified recoverable shale resource due to the emergence of the Utica Shale and additional confidence in associated gas from the Permian Basin. As detailed below, our “max. potential” case assumes about 20% greater recoverable resource relative to the EIA base case, while our “base” case assumes that peak demand by 2050 would only allow for consumption of about 75% of the EIA’s base case.

Exhibit 67: We believe a more aggressive domestic demand expansion is needed to develop identified recoverable natural gas resources in the US

Technically recoverable wet gas resource, Tcf; GS cases are from activity through 2050



Source: EIA, Goldman Sachs Global Investment Research.

Export it all? We see limits to how much LNG exports the global market can take

While we see a temporary wave of coal retirements and a modest level of demand growth from new and expanded petrochemical plants over the next five years, LNG exports currently appears on track to generate the bulk of gas demand growth in the next decade (subject to additional approvals by FERC). About 8 Bcf/d of a total of 17 Bcf/d of filed/approved LNG projects is already contracted. We see healthy demand in the global market for LNG, and we see interest among global consumers to diversify sources of LNG to include North America. Nevertheless, an export based strategy could be constrained by how much LNG the market can accept. In our recent 10-year outlook for the LNG market (see our *Global Gas Watch*, March 31, 2014), we highlighted that the global LNG market appears headed towards oversupply, as progress on export facilities appears to exceed our estimated potential demand growth. In particular, we lowered our target growth for India’s LNG demand on the back of sustained weak buying behavior, as we believe that India will increasingly rely on cheaper coal for its power generation growth. Recent news that China has signed a memorandum of understanding to receive 3.5 Bcf/d of pipeline gas from Russia from 2018 further suggests to us that the global market is likely to bear only up to 9 Bcf/d of US exports by 2025 without negative pricing implications. Given the potential for

further supply growth in the United States, coupled with limits on how much LNG the global market can accept, we believe that the opportunity is best served at home, rather than exporting the value abroad.

Stimulating domestic demand would drive higher US GDP growth than export-focused solution

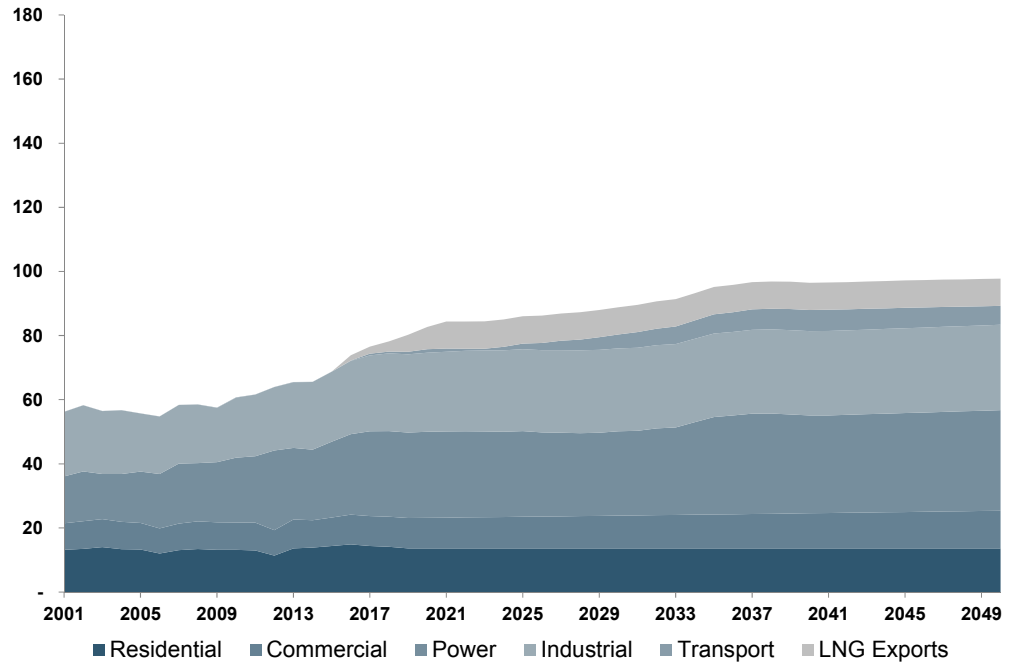
We see three scenarios depending on the level of commitment to domestic gas use. In two of these scenarios, we see gas supply likely to be constrained by demand. We broadly expect natural gas prices to trade in the \$4.00-\$5.00/MMBtu range when shale resource is produced and \$5.50-\$6.50/MMBtu when conventional resource is being developed. This reflects our bottom-up views of individual shale breakevens and historical gas prices in 2002-07 when conventional resource was largely developed.

- **“Base case” scenario: Minimal shift in domestic demand – Prices stay lower for longer, but significant resource is unused.** As highlighted earlier, in our base case scenario, we believe the wave of gas demand growth in 2014-18 largely proves to be short-lived, as coal plant retirements from mercury/air toxics regulations are temporary. This scenario, which assumes only 60% increase in 2050 demand plus LNG imports vs. 2013, should keep gas prices closer to the lower end of the \$4-\$5/MMBtu range in the next decade, in our view. Notably, this scenario assumes only about 75% of EIA-estimated technically recoverable gas resources are used.
- **“Max. potential case” scenario: Meaningful shift in demand – higher prices needed to drive resource upside, but the United States should still remain advantaged; 0.8% p.a. to 2013-50 GDP growth.** As highlighted earlier, we see a 2.5x increase in gas demand in 2050 vs. 2013 in our optimal domestic demand scenario. From a resource perspective, this would warrant about 20% greater recoverable resource than what was identified by the EIA in 2013. We believe further increases in recovery rates from key shale plays like the Haynesville are likely if natural gas prices increase to \$6+/MMBtu. As such, we have assumed greater gas prices and above-EIA estimated technically recoverable resource in our high case scenario. The Goldman Sachs Global Economics Research team believes the incremental production, investment and consumer energy savings in this growth scenario would **improve US GDP growth by almost 1% per year relative to the “base case”**.
- **“Target case” scenario: Moderate shift in demand – Bulk of identified resource is used; 0.4% p.a. to 2013-50 GDP growth.** In our mid-case scenario, we assume a 2.1x greater gas demand in 2050 vs. 2013. This assumes the midpoint of our low and high case scenarios. Our Economics Research team believes the production, investment and consumer energy savings in this growth scenario would **impact US GDP growth by 0.4% per year relative to the “base case”**. We believe the resource needed in this scenario is about in line with EIA-estimated technically recoverable resource. From a pricing perspective, we see shale resource largely keeping \$4-\$5/MMBtu gas prices for about 20 years before moving higher as conventional resource gains share.

Shifting vehicle fuel away from oil would reduce domestic oil demand – exports would likely be needed to avoid reduction in activity levels

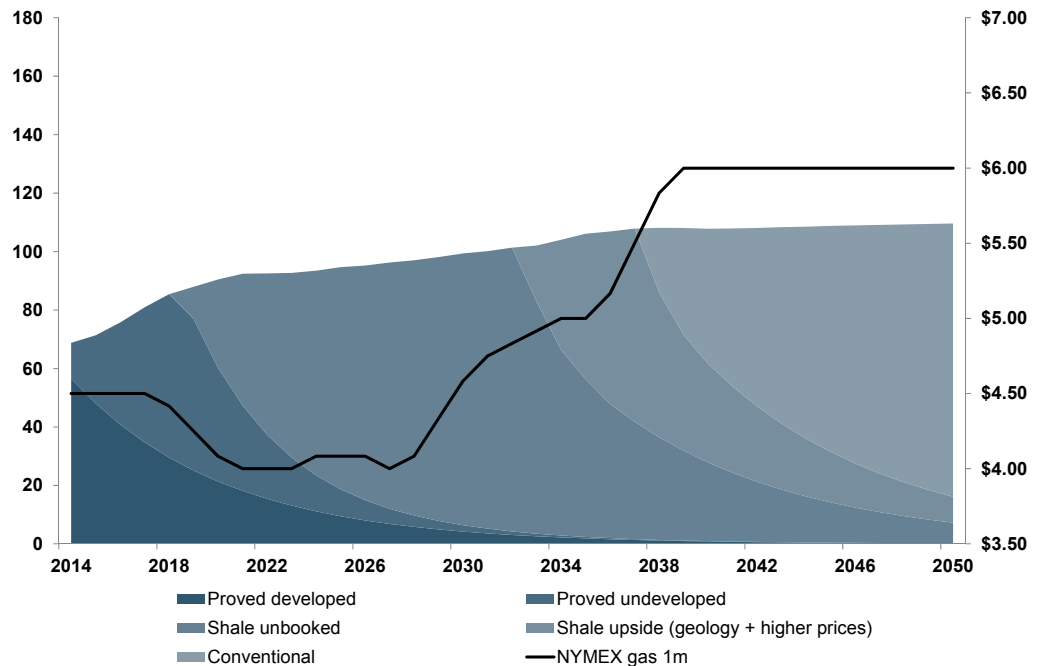
Shifting US vehicle fuel demand to natural gas from gasoline/diesel could materially reduce domestic demand for refined products. Our “max. potential” case assumes 40% of vehicles currently consuming oil-based products shift to natural gas or electricity. Relative to a status quo environment, this would reduce US oil demand by 1.5 mbpd by 2050. To combat the reduced demand, either the United States would need to: (1) materially expand its refined product exports; (2) export oil that would entail a lifting of the existing ban; or (3) reduce oil drilling activity and oil production growth. We believe a lifting of the export ban would make more sense if the United States shifts its demand away from oil as oil price volatility would be less impactful to US consumers.

Exhibit 68: Low case scenario reflects 60% increase in demand by 2050
 Components of US natural gas demand in Bcf/d to meet our low-case demand scenario



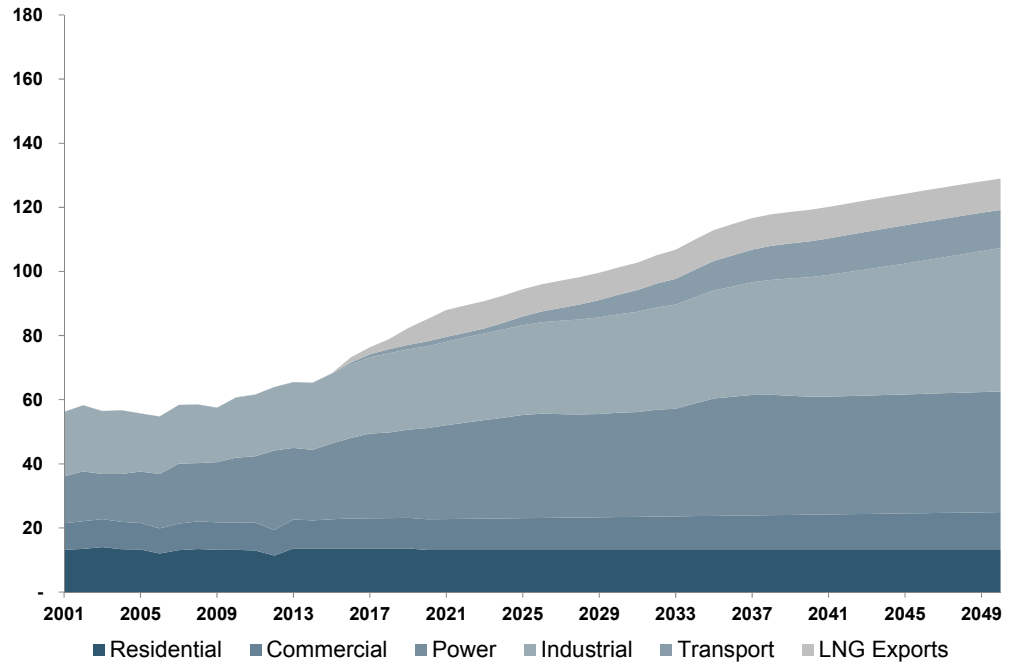
Source: EIA, Goldman Sachs Global Investment Research.

Exhibit 69: Low case scenario implies longer period at bottom end of \$4-\$5/MMBtu range
 Source of gas resource (left axis) in Bcf/d and gas price trajectory (right axis) in \$/MMBtu to meet our low-case demand scenario



Source: EIA, Goldman Sachs Global Investment Research.

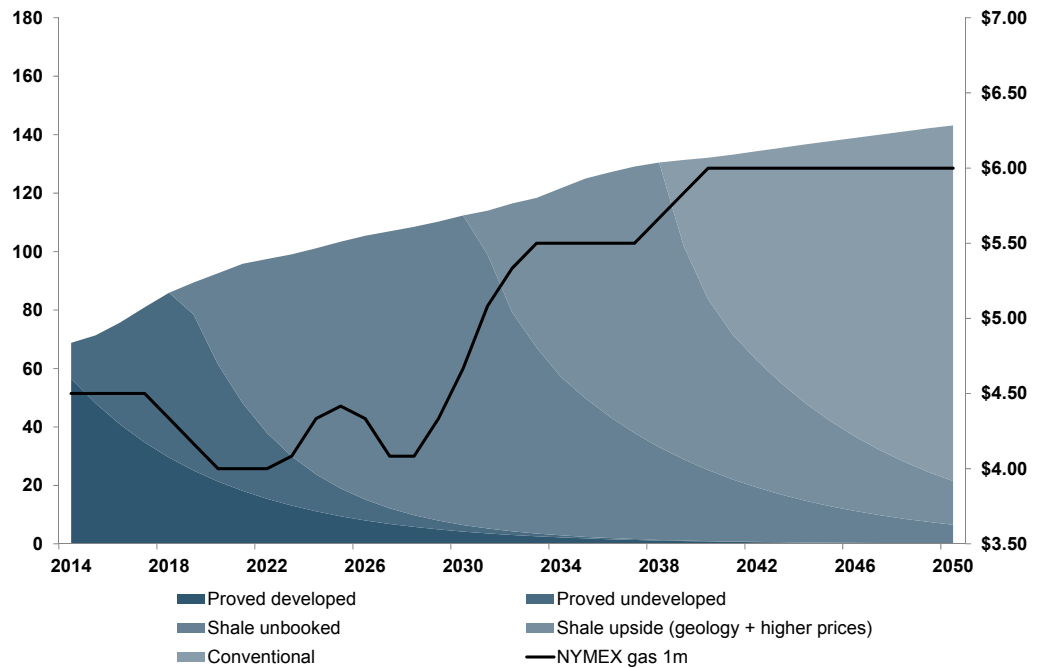
Exhibit 70: Mid case scenario reflects 110% increase in demand by 2050
 Components of US natural gas demand in Bcf/d to meet our low-case demand scenario



Source: EIA, Goldman Sachs Global Investment Research.

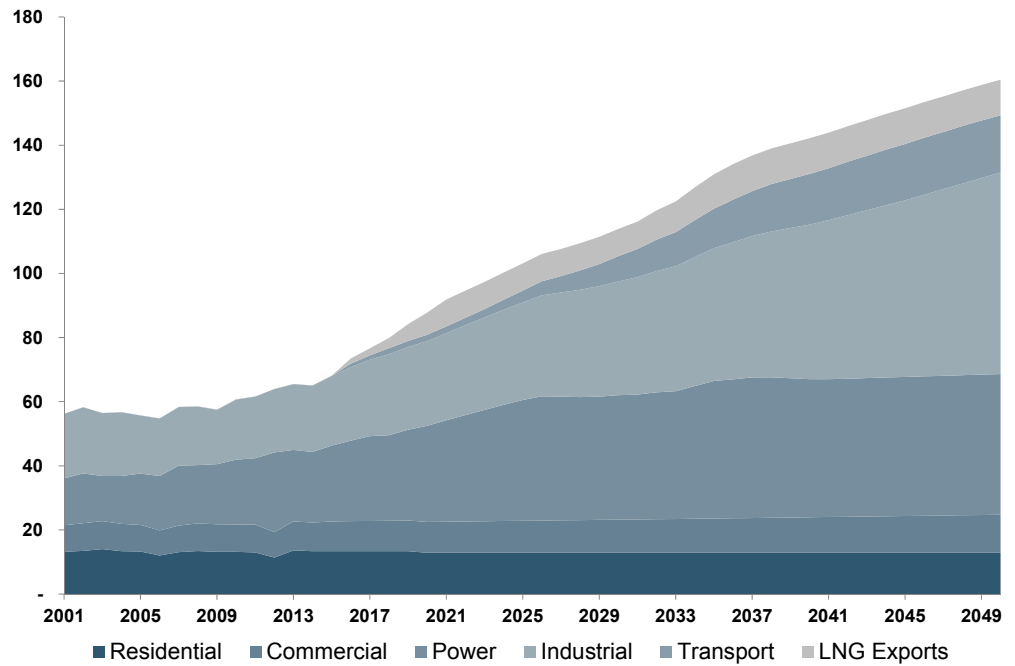
Exhibit 71: Mid-case scenario largely suggests \$4-\$5/MMBtu range for 20 years

Source of gas resource (left axis) in Bcf/d and gas price trajectory (right axis) in \$/MMBtu to meet our low-case demand growth scenario



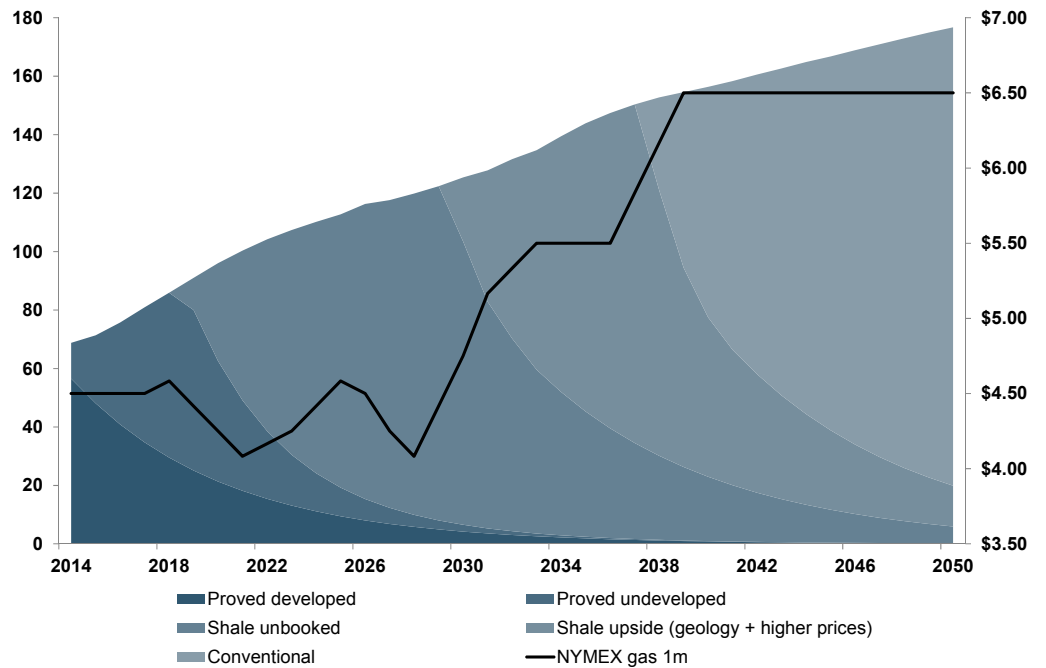
Source: EIA, Goldman Sachs Global Investment Research.

Exhibit 72: High case scenario reflects 160% increase in demand by 2050
 Components of US natural gas demand in Bcf/d to meet our low-case demand scenario



Source: EIA, Goldman Sachs Global Investment Research.

Exhibit 73: High case scenario pushes prices more meaningfully above \$5/MMBtu
 Source of gas resource (left axis) in Bcf/d and gas price trajectory (right axis) in \$/MMBtu to meet our low-case demand scenario



Source: EIA, Goldman Sachs Global Investment Research.

Potential impact of supply-side policy reform: Mexico

Mexican energy reform: Milestones

Despite Mexico's abundant hydrocarbon reserves, its historical under-investment in hydrocarbons E&P has limited the country's ability to create incremental energy supply and to develop the national energy infrastructure.

Led by President Enrique Peña Nieto, the constitutional energy reform bill voted and approved by Mexican State Legislatures (50% + 1 vote) on December 15, 2013, following the approval by Congress on December 12 was aimed at promoting further developments and attracting additional investments in the Mexican energy sector.

Overall, the bill targets modification of the Mexican constitution to allow private participation in the activities of both the energy (E&P, petrochemical, refining, storage, transmission, and distribution) and electricity (generation, transmission, and distribution) sectors.

Next steps

We note that the detailed legislation to be enacted following approval of the constitutional amendments is complex and anticipate it will require considerable debate prior to implementation. The proposed law includes a provision for a 365-day period in which changes to the ordinary laws specific to the energy sector will be enacted.

In our view, debate is likely to be focused on the following issues.

1. The **creation of regulatory agencies**, their administrative structures, roles, and competencies;
2. The creation of the detailed regulation that establishes the main **guidelines of the regulator's functions**;
3. The **definition of the terms for a production-sharing model, a profit-sharing model and a license model** for E&P investments;
4. The enhancement of the **environmental legislation** to be applied to each case;
5. Potential rules of **national content** or **capital internalization**;
6. The **role of Pemex in the new regulatory models**; the proposed law suggests a 10-year period to enable substitutive fiscal planning, given that proceeds from Pemex represent roughly 30% of all fiscal revenues to the Mexican government;
7. Allowing **direct power purchase agreements** with end users for new power generation capacity.

Overall, the reform is expected to open the sector to new growth opportunities particularly by opening to further private investments both in the energy (upstream and midstream) and electricity sectors. For more details, we refer readers to our [Mexican Energy Reform](#) report from January 6, 2014.

Pemex produced 2.5mbpd in 2012 but the current government-take structure severely constrains the company from investing in the exploration for, and development of, new resources. The company currently contributes nearly a third of the federal government's tax revenues, leaving very limited resources for reserve replacement (Exploration and Development) investments.

On the back of both reduced investment and application of new technologies, the number of new discoveries in Mexico has declined sharply over the past decade, resulting in lower production and reserves. In 2012, production declined to 2.5mn bpd from 3.1mn bpd in 2007 and 3.5mn bpd in 2003-2004. In our view, additional investment and technology development are currently required to help leverage Pemex's production capabilities and raise production to over 3.0mn bpd vs. its current production rate of 2.5mn bpd.

As set out in the approved energy constitutional amendments, the Mexican Congress will have to develop, in 2014, detailed tax regulations to facilitate fiscal substitution that gradually reduces Pemex's contribution to Mexican fiscal revenues over a 10-year period and limits the company's contribution to a maximum of 50% of its current contribution.

The exploration and development phase could take 6-10 years following the implementation of detailed regulation (after changes to the ordinary laws specific to the energy sector); and while we assume the current level of Mexican oil production remains stable at the current 2.5mbpd over the next three years, we expect production to re-enter a depletion phase. We believe Pemex could see its revenues (and its contribution to the government) being potentially pressured before any oil related to the new frontiers starts to be developed and produced.

The opportunity is sizeable: Large deepwater resource potential...

In 2012, Pemex made its first significant discovery near the US border (Perdido Fold Belt), having drilled 30 deepwater exploratory wells from 2006. As a result of Pemex's deepwater exploratory campaign, the company estimates that a total 29.5bn boe in recoverable hydrocarbon could be located in the Mexican deep water of the GoM. These opportunities require further exploration / information gathering and would then still require a massive development process.

...coupled with sizable shale opportunity

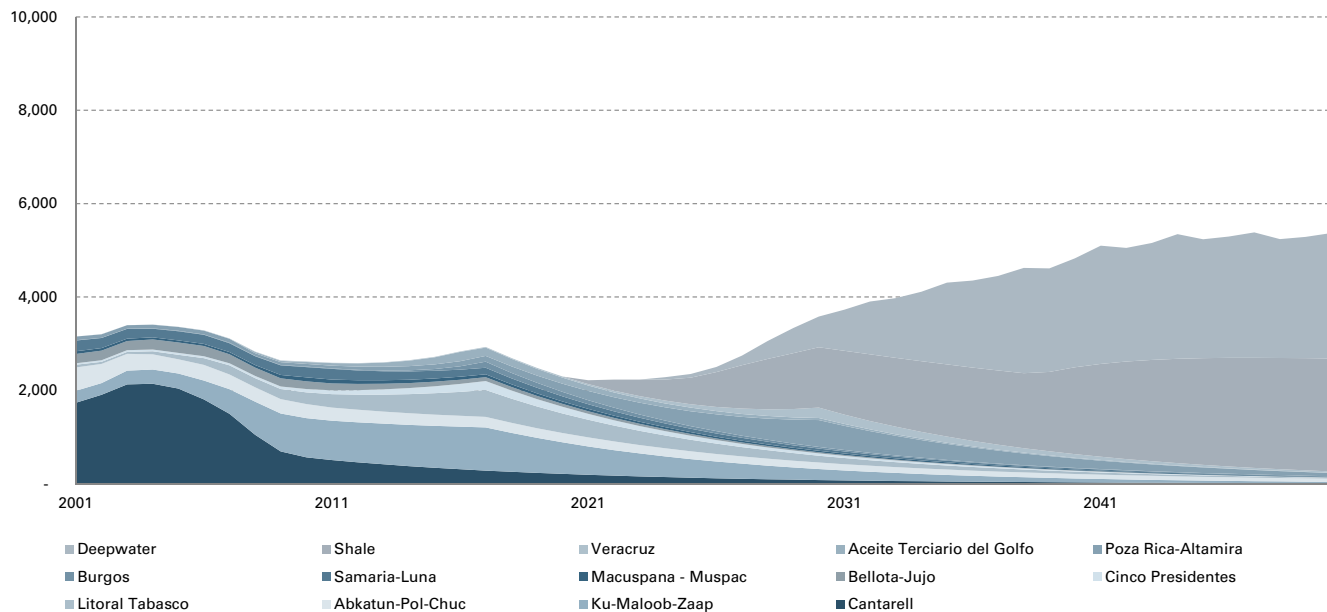
On the shale frontier, Pemex has drilled six shale gas/oil exploration wells in the Eagle Ford shale play in northern Mexico and identified some 200 shale gas resource opportunities (through seismic) in five geologic provinces in eastern Mexico: (1) Chihuahua region, (2) Sabinas-Burro-Picachos region, (3) Burgos Basin, (4) Tampico-Misantla, and (5) Veracruz.

According to Pemex's November 2013 presentation, its shale gas and oil resource assessment equals to 60.2bn boe in recoverable hydrocarbons. We highlight that, given the limited numbers of wells drilled on both frontiers, there is still a considerable amount of drilling required to gather additional information before a conclusive assessment of the potential size of the opportunity can be made. Nevertheless, based on the results of the recent exploratory drilling, as noted above, Pemex expects 29.5bn boe of total recoverable hydrocarbons in deepwater GoM and 60.2bn boe of total recoverable hydrocarbons from the shale-prone areas in Mexico. We estimate these prospective results would require US\$188.2bn in offshore investment and US\$662-US\$1,023 bn in shale investment to fully develop such prospects over a 40-year horizon (beginning 2018-20, our estimate) should the further appraisal confirm resources of such magnitude (see Exhibit 74).

Given the complexity of the shale and deepwater frontiers, where exploration is both capital-intensive and time-consuming, we would not anticipate any robust development capex taking place before 2018-2020. As such, international oil and oil service companies are unlikely to be impacted until then.

Exhibit 74: Mexico oil and gas production estimates (2001-2050)

Oil and gas production (Mboe) – Hypothetical forward curve



Source: Pemex, Goldman Sachs Global Investment Research

The potential economic benefits are large

The near- and medium-term macro-financial outlook for Mexico remains constructive: a reflection of the macro resilience built in recent years and overall disciplined market-friendly policy approach. The economy exhibits no visible macro imbalances—low and stable inflation anchored by a successful inflation targeting and free-floating exchange rate regime, disciplined fiscal policy and a strong external balance sheet—and policy credibility is high.

The Peña Nieto administration managed to overcome years of political gridlock and policy paralysis by forging the needed consensus in Congress to approve during 2013 a far-reaching, deep-cutting package of market-friendly structural reforms—energy (oil, gas, electricity), labor, education, media/telecom, anti-trust, etc.—some of which involved Constitutional changes. Congress is currently debating secondary legislation needed to enable some of these reforms. We expect these reforms to attract domestic and foreign investment into key and hitherto-highly concentrated sectors of the economy (oil and gas and telecommunications) and over the medium-term to help to make the economy more flexible, productive and efficient (i.e., to elevate potential GDP).

Spearheaded by the energy sector reform, the explorations and development of the new shale and deepwater frontiers is likely to attract visible amounts of foreign direct investment over the next 3-4 decades and to gradually lift overall oil and gas production; supporting hydrocarbons exports and overall non-oil investment and household consumption through lower domestic energy costs. We estimate that the direct and indirect diffusion effects of the development of these new opportunities in the energy sector has the potential to lift potential real GDP growth by 1.0 to 1.5 percentage points (potentially more depending on how strong and market-friendly the overall regulatory framework and secondary legislation needed to enable the constitutional reform turn out to be). This could translate into at least 1 million new jobs in the economy over the long-run.

We share the authorities' optimistic view about the potential transformational impact of the energy reform and its potential impact on FDI, productivity growth, job creation, and ultimately living standards, but believe the benefits and dividends of such reforms may be somewhat more back-loaded than anticipated. That is, tangible benefits of the energy sector reform are expected to accrue mostly over the medium- and long-run, starting incrementally around 2020, given the natural geological and technological complexities of developing virtually new oil and gas fortifiers.

Overall, we remain positive and fundamentally constructive on the macro outlook for Mexico given the business friendly non-interventionist policy approach, the expected recovery of the US economy, and the expected medium-term boost from the recently approved structural reforms. These attributes contribute in a significant way to differentiate Mexico positively from most other large global EMs.

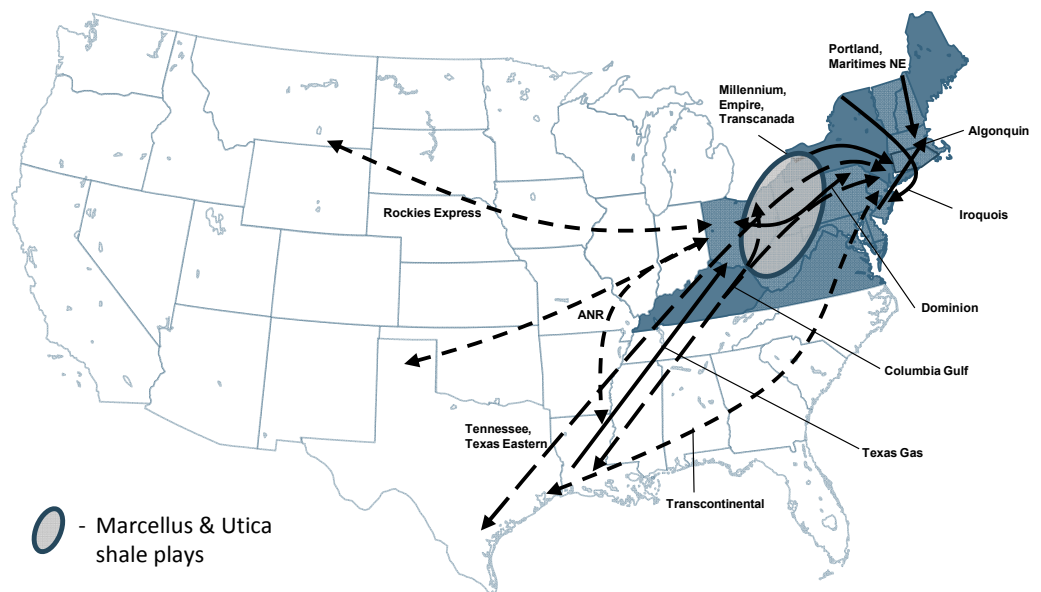
Infrastructure commitment needed for supply to meet demand

Disparities in pipeline connectivity between supply and demand have regionalized the impact of the shale revolution

The shale revolution has not been felt equally throughout North America, partly because of natural geographical disparities between supply/demand and partly because of a lack of connectivity that has limited the flexibility for natural gas to reach certain regions. Historically, the Northeast portion of the United States has seen the highest natural gas prices because the supply sources for gas – the Gulf Coast – required significant transportation (see Exhibit 75).

Exhibit 75: The US Northeast high-consuming area has historically been supplied by large pipeline imports from the rest of the country

Main pipeline systems serving the Northeast. Dashed arrows can or soon due to flow bi-directionally

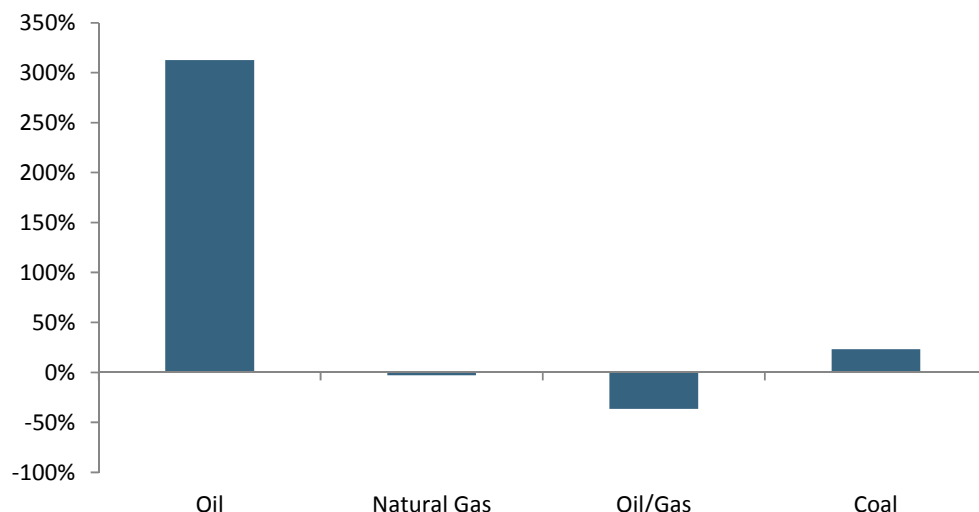


Source: Goldman Sachs Global Investment Research.

More recently, the Marcellus Shale has been the single greatest growth contributor to US natural gas supply. This has substantially lowered regional prices around the Marcellus in Pennsylvania primarily, but areas like New England have not been as affected due to more limited connectivity. This past winter, when abnormally cold weather drove significant increases in power and natural gas demand in the Northeast, infrastructure constraints – especially pipelines – forced coal- and oil-fired power generation to run more in New England. Gas-fired plant out-levels did not increase versus 2013, driven by pipeline congestion (see Exhibit 76).

Exhibit 76: This past winter, pipeline constraints prevented gas from adequately responding to demand in New England

Year-on-year percentage change in power generation by fuel source, January-April



Source: ISO New England.

We see a substantial need for gas infrastructure expansion. We believe a commitment to developing US natural gas resources and growing US gas consumption also requires a commitment to infrastructure expansion without sacrificing environmental goals. This is a key area in which policymakers at the state/federal level along with industry can work together, in our view.

We see two key areas that require focus – greater connectivity to New York/New England and shift to move Marcellus/Utica gas south and west

Of these, the southward/westward shift of Marcellus/Utica gas appears more on track.

- (1) **Geographical disparity between supply growth and demand growth to result in \$21 bn in infrastructure investment in next five years.** We estimate 85% of net US production growth in 2014-18 will come from Appalachia (the Marcellus and Utica shales) in the Northeast, while 60% of US demand growth (including projected LNG/pipeline exports) will come from the Gulf Coast. We believe this will result in a \$21 billion of investment to reverse pipelines and build new pipelines from Appalachia to the support substantial changes in gas flows for supply to meet demand. We believe this is largely on track without meaningful shift in policy, though this will require continued work by FERC and state authorities.
- (2) **Connectivity to increase reach of Marcellus/Utica to New England area appears to be moving more slowly at present.** We see an opportunity for industry and state/federal regulators to more closely work together to connect New England and portions of the Northeast with growing supply in Appalachia. While there have been proposals for new pipelines out of the Marcellus to tap into existing interstate pipelines, the timing of approvals are unclear. Policy and market design adjustments throughout the Northeast appear necessary to enable more potential gas/power customers – whether those of regulated utilities, merchant power companies or large commercial/industrial companies – to enter multi-year gas/power contracts that could then stimulate more gas infrastructure development. Alternatively, clarity to producers that pipeline expansions will be approved over an acceptable investable time horizon are likely to be needed for producers to fund new pipelines. Both of these outcomes

could lead to additional supplies of gas flowing to New England markets and accommodate greater residential/commercial use of natural gas, reducing the use of fuel oil.

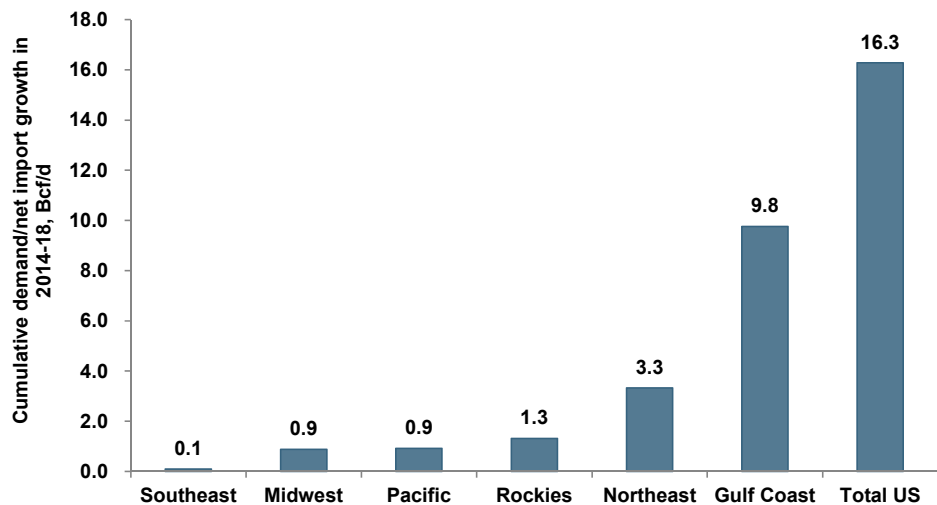
Resource in other areas will ultimately be needed over the longer term – commitment that infrastructure challenges will be met is key for investment

While the Marcellus/Utica will likely be the greatest contributors to natural gas supply growth in the next 5-10 years, substantial gas resource in other areas like the Gulf Coast and US/Canadian Rockies that will be needed for longer-term development. Since these areas have largely been producing areas for some time, the infrastructure needs may be less pronounced. Nevertheless, investment decisions by potential gas consumers are unlikely without confidence that the infrastructure will be in place to support requisite supply.

Another potential option is to focus demand growth in greater proximity to supply growth, which does not appear on track

Our expectation at present is that the Gulf Coast will likely see the bulk of industrial expansion, mainly because that is where the petrochemical centers have historically existed. There are plans to build petrochemical facilities in Appalachia, though it is not clear whether those will proceed. Consideration of focusing the expansion of petrochemicals in areas such as Appalachia would reduce gas infrastructure needs but would require additional infrastructure to support movement of petrochemical products.

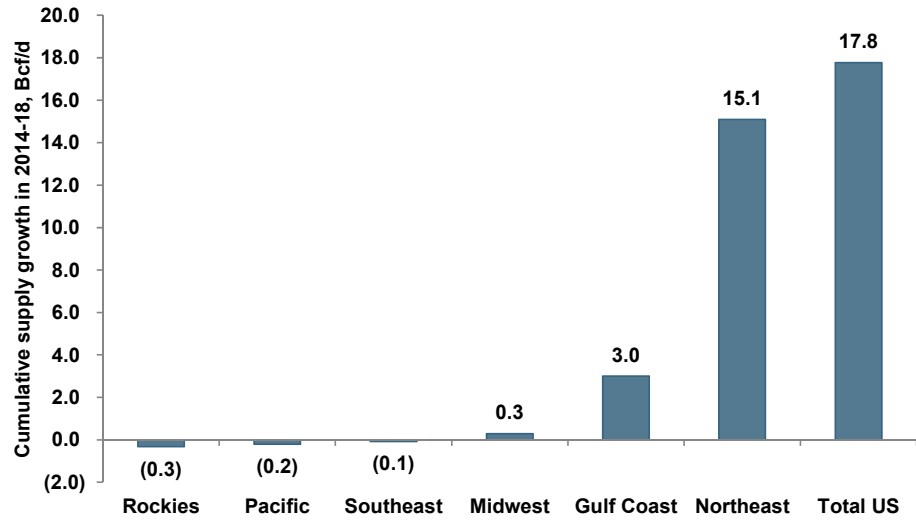
Exhibit 77: Gulf Coast area driving bulk of 16 Bcf/d of 2014-18 demand growth
Demand by region, in Bcf/d (Northeast includes New England and Mid-Atlantic)



Source: EIA, Goldman Sachs Global Investment Research

Exhibit 78: Appalachia is driving the bulk of 18 Bcf/d of 2014-18 supply growth

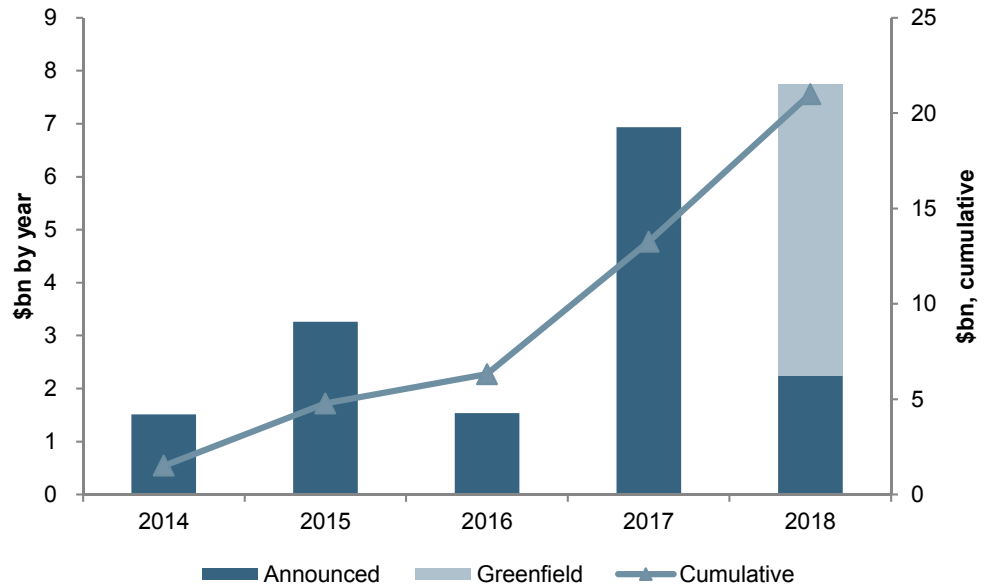
Production by region net of lease/plant/pipeline fuel, in Bcf/d



Source: EIA, State data, IHS, Goldman Sachs Global Investment Research.

Exhibit 79: We expect \$16 bn of pipeline reversals and \$5 bn of newbuilds in 2014-18

Expected capital outlay for new Marcellus/Utica pipeline connectivity, \$ bn



Source: Goldman Sachs Global Investment Research.

Glossary

Bcf/d:	Billion cubic feet per day.
BOE:	Barrel of oil equivalents. A unit of energy based on the approximate energy released by burning one barrel (42 US gallons) of crude oil.
Btu:	British thermal unit, a unit of energy equal to about 1,055 joules.
CAFE:	Corporate Average Fuel Economy, refers to annual miles per gallon standards set for a vehicle manufacturer's entire fleet of passenger and light trucks manufactured for sale in the US for each model year. Miles per gallon are calculated on a gasoline gallon equivalent basis.
Capacity factor:	Total actual output of a power plant as a percentage of its total potential annual output.
CCGT:	Combined Cycle Gas Turbine – natural gas power plants with low heat rates and greater efficiency – requiring fewer Btus per unit of power (kWh) produced.
CNG:	Compressed Natural Gas, refers to pressurized natural gas. Under this condition the natural gas remains clear, odorless, and non-corrosive.
Conventional gas:	Gas trapped in rock structures due to folding and/or faulting of layers of sedimentary rock. Vertical drilling is normally used to recover conventional gas.
CO2:	Carbon dioxide.
CO2e:	CO2 equivalent, a measure of greenhouse gas emissions.
Deepwater drilling:	The drilling of oil and natural gas at water depths of 1,000 feet or greater.
Dry gas:	Natural gas that contains mostly methane and little-to-no heavier hydrocarbons.
EIA:	Energy Information Administration.
Ethane:	The highest-volume NGL. The only industrial use for ethane is as a feedstock into a steam cracker for the production of ethylene.
Ethylene:	A basic commodity petrochemical that is the building block for the chemical industry. The highest volume petrochemical with 130mn tons produced each year and installed capacity of 150mn tons globally. Can be created from a variety of feedstocks including ethane, propane, butane, gas oil, condensate, and naphtha.
EV:	Long-range electric vehicles powered solely by electricity. It does not refer to hybrid electric vehicles or plug-in hybrid electric vehicles, both of which have short electric battery ranges and rely upon gasoline as a fuel source.
E85:	Mixture of 85% ethanol and 15% gasoline used as a substitute to gasoline in flex fuel vehicles. One gallon of E85 has two-thirds the range of an equal amount of gasoline.

E100:	Pure ethanol. It can be used in ethanol-only and flex fuel engines.
FCV:	Fuel Cell Vehicle. The vehicles are equipped with fuel cells that generate electricity through the use of hydrogen gas.
Federal buyers' tax credit:	Government subsidy applicable to purchases of electric vehicles, which reduces the total amount of income tax owed.
Feedstock:	The raw material used in a chemical process to make desired petrochemicals. Typically this is a hydrocarbon. Examples include ethane, propane, butane, gas oil, condensate, and naphtha.
FFV:	Flex Fuel Vehicle. Capable of running on either gasoline or E85, typically in the United States.
GGE:	Gasoline Gallon Equivalent, amount of alternative fuel needed to equal the energy content in one gallon of gasoline.
GW:	Gigawatt – a unit of electric generation capacity, the equivalent of 1,000,000 kW.
Heat rate:	Measurement of the efficiency rate of a power plant, measured in Btu's needed to produce one kWh.
Horizontal drilling:	Drilling at an angle to the vertical, so that a well runs parallel to the formation being drilled containing oil or gas.
Hydraulic fracturing:	The process of creating fractures in the rock formations to stimulate crude oil and natural gas production. The fractures are created by injecting fluid (water in most cases) with sand and other additives at high pressure.
ICE:	Internal Combustion Engine; it is the dominant engine technology used in traditional powertrains for gasoline and diesel fueled vehicles.
kW:	Kilowatt – a unit of electric generation capacity.
kWh:	Kilowatt hour – A unit of electric generation output or demand.
LCOE:	Levelized cost of electricity.
Mcfe:	One thousand cubic feet equivalents. A unit of energy based on the approximate energy released by burning one thousand cubic feet of natural gas. 6 Mcfe is equivalent to 1 BOE.
Methane:	The principal component (90%-99%) of natural gas. Used for power generation, chemical production (notably methanol, ammonia, hydrogen, and syngas), heating, cooking, etc.
Methanol:	A simple alcohol that is commercially produced in large volumes. Annual demand is 65m tons and there are 100m tons of global capacity. Roughly half of current production is used to make other chemicals (notably formaldehyde and acetic acid) with another 10% used to make olefins and around 40% used as a transportation fuel (including the fuel additive MTBE). A corrosive liquid that is toxic to humans.
MJ:	Megajoule, measure of energy density. It is equal to one million joules, or the kinetic energy of a one-tonne vehicle moving at 160km/h (100mph).

MW:	Megawatt –a unit of electric generation capacity, the equivalent of 1,000 kW.
MWh:	Megawatt hour, a unit of electric generation output or demand, the equivalent of 1,000 kWh.
M85:	Mixture of 85% methanol and 15% gasoline used as a substitute to gasoline in flex fuel vehicles. One gallon of M85 has half the range of an equal amount of gasoline.
Natural gas-based ethanol:	Ethanol produced from natural gas as opposed to crops (corn, sugar). Chemically the same as bio-based ethanol. Does not qualify for the RFS in the United States.
Naphtha:	A steam cracker feedstock that come from oil refineries. Chemically it is very similar to gasoline. Used primarily as a feedstock into a steam cracker for the production of ethylene.
NEB Canada:	National Energy Board, Canada.
NGLs:	Natural Gas Liquids. The heavier hydrocarbons that are naturally found mixed with methane (natural gas) in a gas deposit. In order of heat content they are ethane, propane, butane, and natural gasoline. Natural gas is processed to remove NGLs, which are then fractionated into their individual components of ethane, propane, butane, and natural gasoline.
NOAA:	National Oceanic and Atmospheric Administration, a US federal government agency.
OEM:	Original Equipment Manufacturer. The term refers to automobile companies.
Peakers:	Natural gas power plants with higher heat rates and lower efficiency relative to combined cycle gas turbines (CCGTs).
Propylene:	A basic, commodity petrochemical that is the building block for the chemical industry. It is most commonly produced as a by-product in the production of ethylene via a steam cracker, but it is also produced as a by-product of oil refineries or on-purpose by propane de-hydrogenation (PDH) units.
Proved reserves:	Resources that can be estimated with reasonable certainty to be economically producible in the future from known reservoirs and under current economic, operating and regulatory conditions.
REN21:	Renewable Energy Policy Network for the 21st Century (see http://www.ren21.net/ for more information).
RFS:	Renewable Fuel Standard. US requirement that transportation fuel contain a minimum volume of renewable fuels, including ethanol.
RPS:	Renewable Portfolio Standards, state regulations or mandates requiring a certain percentage of demand or power generation comes from renewable resources.
RVP:	Reid vapor pressure. The term refers to a liquid fuel's evaporation characteristics and is a common measure of the volatility of gasoline.

Shale gas:	Natural gas that is tightly trapped inside shale formations that is typically recovered using unconventional drilling technology. Shales are fine-grained sedimentary rocks.
Steam cracker:	A chemical plant that creates olefins (e.g., ethylene, propylene, etc.) by cracking feedstocks (e.g., ethane, propane, naphtha, etc.) into smaller unsaturated hydrocarbons through extreme heat and pressure. A world-scale steam cracker typically has greater than 1.0m tons of ethylene capacity and can cost \$3-\$5bn to build, with construction typically taking 5 years including engineering and permitting.
Tcf:	Trillion Cubic Feet, measure of volume used in the gas industry.
Technically recoverable reserves:	Resources that can be recovered/produced using current recovery technology unrelated to economic profitability.
Unconventional gas:	Gas that is trapped in impermeable rock and unable to migrate to form a conventional gas deposit. Horizontal drilling is normally used to recover unconventional gas.
Unproved reserves:	Reserves that are based on geologic and/or engineering data similar to that used in estimates of proved reserves, but technical, contractual, economic, or regulatory uncertainties preclude such reserves being classified as proved.
Well-to-wheel:	Also known as life cycle assessment. It is an analysis of a fuel's cumulative CO ₂ e emissions or environmental impact from extracting the necessary feedstock, through refining and distribution, to the actual vehicle consumption.
Wet gas:	Natural gas that contains a fair amount of heavier hydrocarbons (like ethane, propane, butane and other higher hydrocarbons) which are condensable. These are frequently separated into natural gas liquids (NGLs).

Exhibit 80: Recent trends in US greenhouse gas emissions and sinksTg or million metric tonnes CO₂e

	1990	2005	2008	2009	2010	2011	2012	Change 1990-2012
Electricity								
Electricity Generation								
CO ₂	1,820.8	2,402.1	2,360.9	2,146.4	2,259.2	2,158.5	2,022.7	11%
Electrical Transmission and Distribution								
SF ₆	26.7	11.0	8.4	7.5	7.2	7.2	6.0	-78%
Subtotal Electricity	1,847.5	2,413.1	2,369.3	2,153.9	2,266.4	2,165.7	2,028.7	10%
Oil and Gas								
Natural Gas Systems								
CO ₂	37.7	30.0	32.7	32.2	32.4	35.1	35.2	-7%
CH ₄	156.4	152.0	151.6	142.9	134.7	133.2	129.9	-17%
Petroleum Systems								
CO ₂	0.4	0.3	0.3	0.3	0.3	0.3	0.4	0%
CH ₄	35.8	28.8	28.8	29.1	29.5	30.5	31.7	-11%
Subtotal Oil and Gas	230.3	211.1	213.4	204.5	196.9	199.1	197.2	-14%
Total Electricity, Oil and Gas	2,077.8	2,624.2	2,582.7	2,358.4	2,463.3	2,364.8	2,225.9	7%
Total GHG emissions	6,233.2	7,253.8	7,118.1	6,662.9	6,874.7	6,753.0	6,525.6	5%
Percent Electricity, Oil and Gas	33%	36%	36%	35%	36%	35%	34%	
Percent Electricity	30%	33%	33%	32%	33%	32%	31%	
Percent Oil and Gas	4%	3%	3%	3%	3%	3%	3%	

Source: EPA

Exhibit 81: Methane emissions from natural gas systemsTg or million metric tonnes of CO₂e

Stage	1990	2005	2008	2009	2010	2011	2012	Change 1990-2012
Field Production	56.0	67.3	64.0	53.9	48.2	42.6	41.8	-25%
Processing	17.9	13.7	14.9	16.1	15.1	17.9	18.7	4%
Transmission and Storage	49.2	41.2	43.1	44.3	43.4	45.2	43.5	-12%
Distribution	33.4	29.7	29.6	28.7	28.1	27.5	25.9	-22%
Total	156.5	151.9	151.6	143.0	134.8	133.2	129.9	-17%

Source: EPA.

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