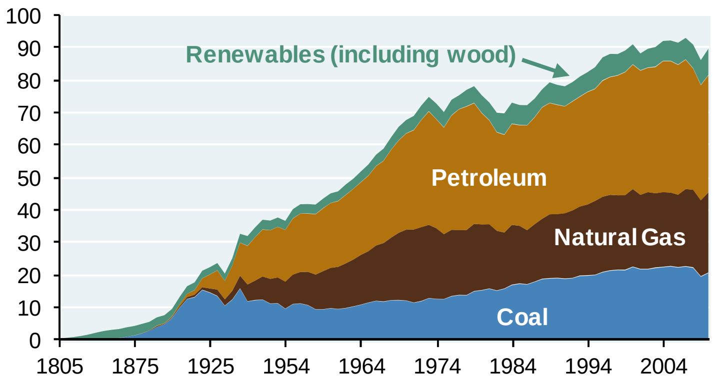
***Reservoir Digs*: on energy investing and private equity**

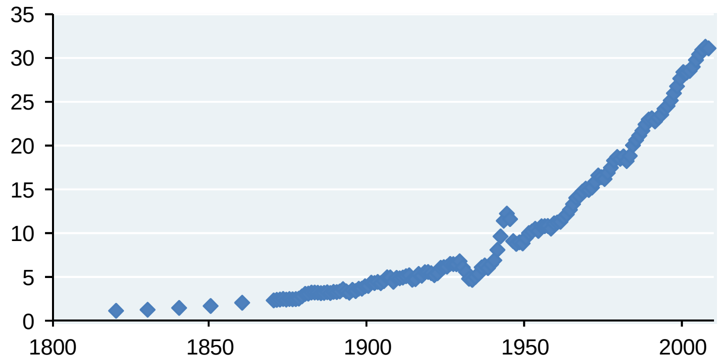
We try to invest as much in the things people *need* as in the things they *want*. While our pre-IPO digital media investments will be interesting to watch, investments in healthcare, industrials, consumer staples and energy in aggregate play a larger role in our portfolios. The charts below show the well-understood contribution of energy to rising per capita GDP since 1800. There are fierce debates about the long-term externalities involved with fossil fuels, but it seems clear that we will be living in a carbon-driven world for the foreseeable future. We have written in the past about the enormous challenges that renewable energy faces before it makes a larger contribution, and will not do that again here[1]. Oil and natural gas play a central role in the global economy that will not be easily disintermediated away.

US primary energy consumption by source
Quadrillion BTUs



Source: EIA. Data as of 2010.

US per capita GDP
Real constant dollars, thousands

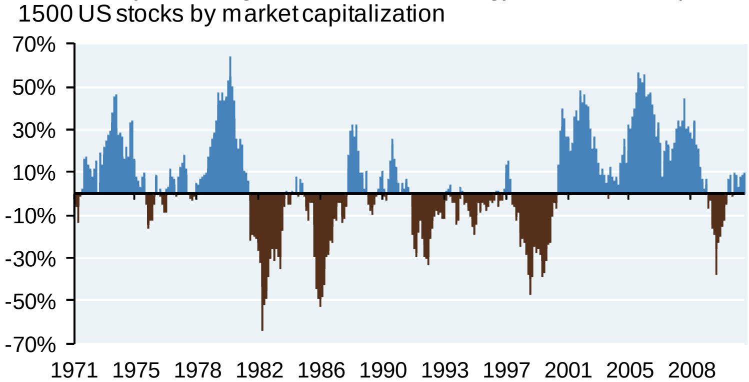


Source: *"Statistics on World Population, GDP and Per Capita GDP, 1-2008 AD"*, Angus Maddison, University of Groningen.

<u>Getting started: publicly tradable energy stocks</u>

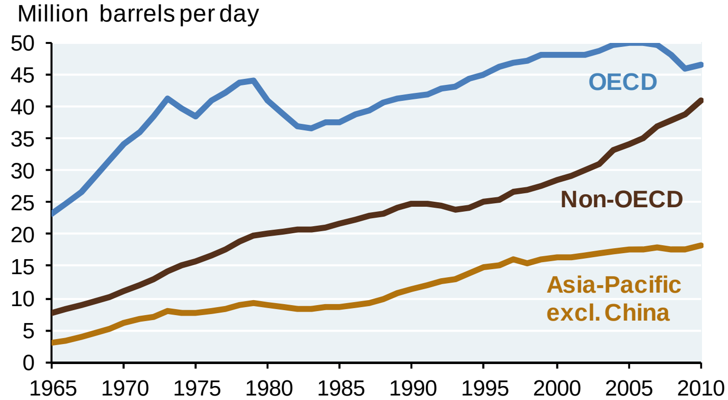
After two long decades of underperformance (1980-2000), energy stocks have done well over the last decade, a reflection of rising non-OECD growth and energy consumption, rising crude prices, and declining spare crude oil capacity. Within the non-OECD, much of the demand has of course come from China; in the chart below, Asia-Pacific ex-China demand hasn't grown that fast. Energy stocks have also been very volatile, registering the 2nd highest sector volatility, behind only financials (sorry about that). In the last couple of years, several factors have constrained energy outperformance. Energy is very capital-intensive (the sector's capital spending to depreciation ratio is 50% higher than the market), and costs of producing the marginal barrel of oil have been rising as well (see EoTM Feb 27). As a result, energy RoEs are not much higher than the market, despite rising oil prices. Many barrels extracted now were probably first discovered in the 1990's, when marginal costs were much lower; the cost of replacing these barrels is much higher today. In addition, environmental liability risks and the possibility of windfall profit taxes (such as those proposed by Senator Obama during the 2008 Presidential campaign) are always present.

Relative performance of Energy sector
Percent, 2-year rolling relative return of energy stocks to the top 1500 US stocks by market capitalization



Source: Morgan Stanley.

Global oil consumption
Million barrels per day



Source: BP Statistical Review.

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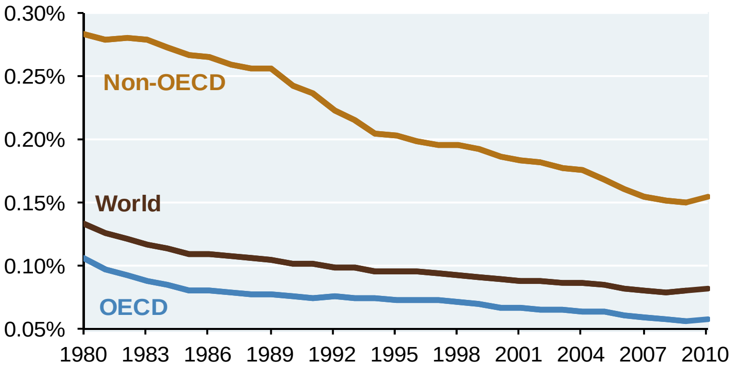
[1] See "*Another Don Quixote Thanksgiving*" (Nov 19, 2011) on energy myths and realities surrounding fossil fuels and alternative energy. A recent development: Spain's energy regulator proposed paying power plants to halt solar plant construction, to both reduce expenditures *and* reduce electricity costs. Spain's kWh per m^2 of solar irradiation is the highest in Europe, so it is a good test case. A recent Bloomberg article cited profitable investments in US solar wind farms. However, the favorable economics mentioned appear predicated on guaranteed per MW-hour contracts that are 2x-3x current wholesale power prices, debt guarantees, cost reimbursements and accelerated tax credits.

***Reservoir Digs*: on energy investing and private equity**

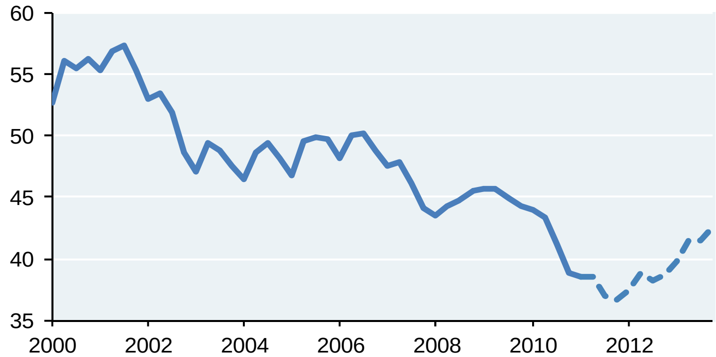
Non-OECD oil consumption has been rising despite declines in oil intensity, as shown below. If energy efficiency were to increase and if countries in the Middle East and Asia reduced domestic gasoline subsidies, global oil demand could fall 1-2 million barrels per day. If such a demand decline took place, given how tight global supplies are (2nd chart), oil prices might fall to $85-$90 per barrel. That's where equity markets appear to be forecasting long-term oil prices (a view based on extrapolating the market-implied oil price from current stock prices, long-term cash flow projections and costs of capital).

Oil intensity declining worldwide
Billions of barrels/real GDP (constant 2000 USD, trillions)



Source: ISI Group, International Energy Agency, World Bank.

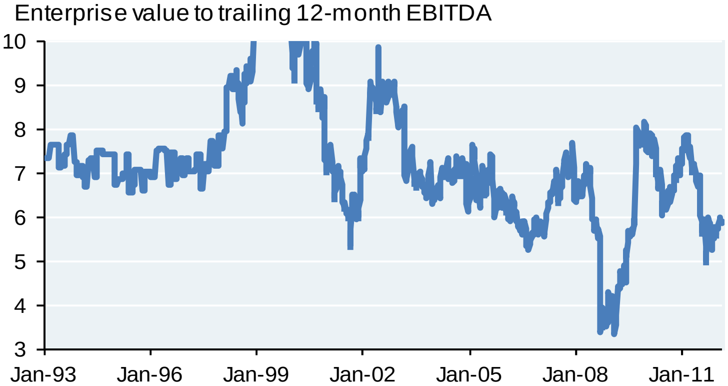
Global oil inventories to build (modestly) in 2012
Days of demand



Source: IEA, ISI Energy Research.

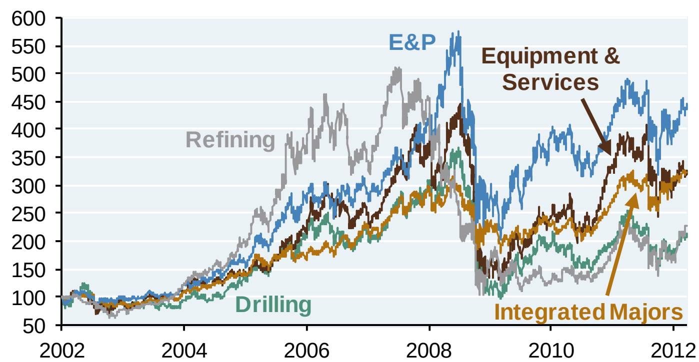
Energy valuations are currently inexpensive vs. history (see chart below, left), which reflects in part markets not willing to assume oil prices sustainably above $100 per barrel. There's nothing unique about low valuations right now; non-energy valuations are low compared to history as well. A scan of price-to-book ratios, cash flow ratios and profit yields shows that energy stocks are a *little* bit cheaper vs. their history than the rest of the market, but not by much[2]. Energy is a very broad category that includes integrated oil companies, and companies focused on exploration and production, services, refining, storage and transportation, and drilling. **As shown, energy sub-industry returns have been quite different, with refining and drilling trailing the rest. To be sure, they were all clobbered by the Great Recession, with Integrated Oils holding in better than the others. In terms of volatility, it's a tale of two extremes: drilling/services are the most volatile of all S&P industries, while integrated oils are in the middle of the pack**.

S&P 500 Energy sector
Enterprise value to trailing 12-month EBITDA



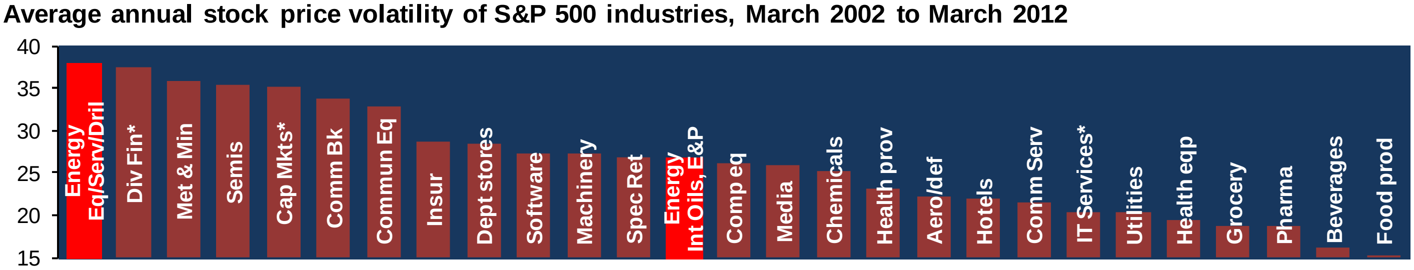
Source: Bloomberg.

Total return of S&P 500 Energy sub-industries
Index, 1/1/2002=100



Source: Bloomberg.

Average annual stock price volatility of S&P 500 industries, March 2002 to March 2012



Source: Bloomberg; computed for all S&P 500 GICS industries with at least 8 constituent members. *Data for Div Fin, Cap Mkts, & IT Serv starts in July 2004.

[2] Empirical Research Partners weekly portfolio strategy report, February 29, 2012, Exhibits 19-21.

***Reservoir Digs*: on energy investing and private equity**

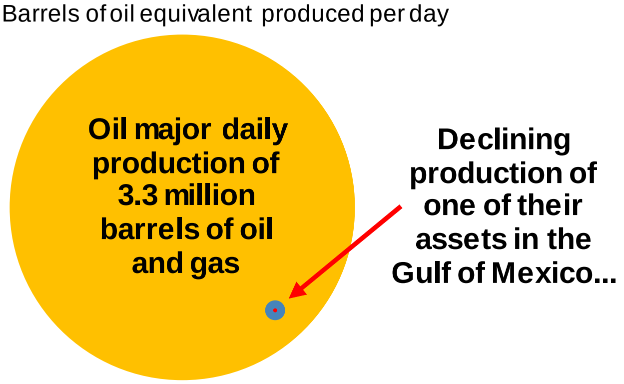
Why private equity capital in the energy space?

The acronym "E&P" refers to exploration and production, but like the phrase "broker-dealer"[3], there's a big difference between the former and the latter, with one much riskier than the other[4]. The private equity strategies we find most interesting put a lot more emphasis on production (e.g., enhancing production of existing wells, aggregating depleting properties) than on pure exploration, although horizontal drilling and other technological improvements have reduced exploration risks at onshore and shallow water locations. Complementing exploration and production are midstream opportunities (pipelines and storage) and related energy and power services. The best way to convey the risks and opportunities of energy investing and private capital is to look at what some managers actually do. "Assets in transition" is a common theme, highlighting a focus on companies or properties that needed to be recapitalized, reconfigured or restructured. We walk through 5 examples below.

I: Circling the majors for unloved oil and gas properties

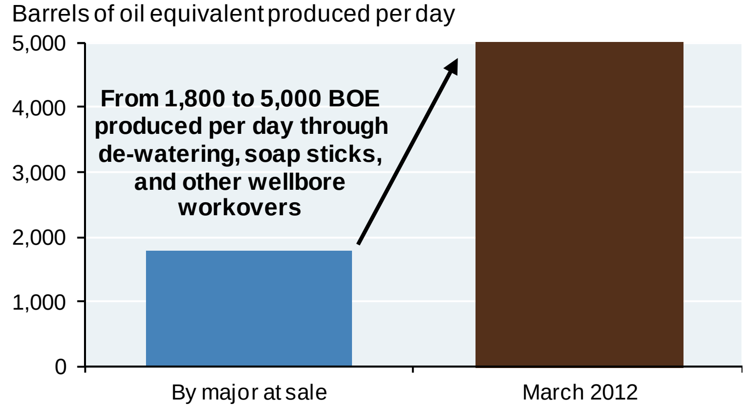
In the pie below, we plot the daily production of a large major oil company, which by itself accounts for ~2% of global oil production. The small inset blue dot is one of their properties in the Gulf of Mexico at its peak of 50,000 barrels per day; and the smaller, almost invisible red dot inside the blue dot is where this property's daily production had fallen to (1,800 barrels per day). Should every property that runs out of steam be shuttered? Like the tree in *A Charlie Brown Christmas*, sometimes all these properties need is a little love. In the hands of more focused ownership, and with some capital investment, production can be increased. As shown on the right, new owners increased production to 5,000 barrels per day, creating value in excess of the required capital reinvestment. This would not have moved the needle for the original owner, but was a success for the new one.

Too small to care about?
Barrels of oil equivalent produced per day



Source: Company report, J.P. Morgan Private Bank.

...gets a second life in new hands
Barrels of oil equivalent produced per day



Source: J.P. Morgan Private Bank.

What's involved with resuscitating old wells? Terms like "recompletion" and "workover" refer to things like producing from different depths in the same well; de-watering the well bores to allow for faster oil flow; using "soap sticks", which act like seltzer and lighten the fluid column which also creates faster oil flow; and acidizing reservoir rock to dissolve sediment and mud. None of these activities are ground-breaking from a technology perspective (some are remarkably low-tech), but have proven to be effective. Many ideas come from the existing operators of the facility, who believe they know what might work, but cannot get management time or attention to approve them. Another way to increase value: offshore platforms often have built-in oil separation and processing capacity. Regarding the property above, as production declined, its co-located processing capacity lay dormant in the hands of an E&P major. But in the hands of a private owner, there is no competitive reason not to lease this processing capacity to other E&P companies, generating additional cash flow.

In addition to E&P majors, other sellers include service companies looking for a higher P/E multiple (E&P properties tend to drag them down), and undercapitalized owners who cannot make necessary reinvestments. The Gulf of Mexico is an interesting place to look for these opportunities, since many companies are diverting capital and management attention to onshore shale

[3] In the mid 1970s, broker-dealers like Merrill, DLJ and A. G. Edwards were leveraged from 5-to-1 to 8-to-1. **Most activity was brokering (acting as agent), not dealing (acting as principal).** Commission deregulation reduced core profitability (commissions declined from 61% of industry revenues in 1965, to 40% in 1976, to 16% in 1990), so many firms migrated to higher leverage and risk. Broker-dealer "risk-based revenues" rose from 42% in 1980 to 64% in 1989, and by the late 1980s, leverage at Merrill, First Boston, Bear Stearns and Morgan Stanley rose to 21, 65, 74 and 50, respectively. In 2004, the SEC eliminated the net capital rule that limited broker-dealer leverage to 12-1 since 1975. In 2006, broker-dealers were leveraged around 30-35, and the rest is history.

[4] **Another example**. Early stage drug discovery efforts often experiment with thousands of compounds to derive just a few that enter Stage 1 FDA clinical trials. We prefer the lower risk/return profile of Stage 2 and 3 trials when investing in biotechnology.

plays. Another reason for lower prices: hurricane risks and operating costs (particularly after the BP spill), and the requirement to recognize very large "plug and abandonment" liabilities when a well is drilled. The well above was part of a broader package of acquisitions and production improvements on existing and new wells. The entire package ended up being attractive to a strategic buyer looking for proven reserves.

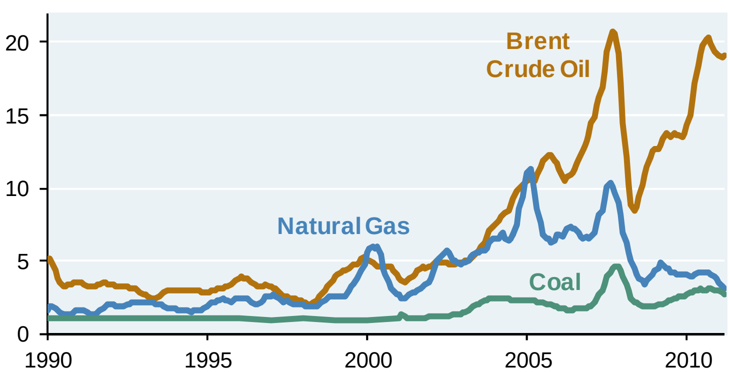
Risks: the cost of dealing with a depleted well. Plug and abandonment (P&A) activities have to take place within one year of the end of a well's productive life. Increasing proven reserves helps to stretch this out, but eventually, the day of reckoning comes. This can be a substantial risk for investors in heavily depleted properties. Usually, decommissioning companies will perform these services on a cost-plus basis. However, in the transaction cited above, the private equity owner was able to negotiate a fixed-price contract (above which the P&A company takes the risk), and escrowed this amount in around one year.

The other risk: the weather. Hurricane risks in the Gulf are substantial, and difficult to insure on a cost-effective basis. It took 3 years to repair some of the offshore pipelines that were damaged by Hurricane Katrina, reducing the value of producing assets. Furthermore, if an oil platform sustains serious damage from a hurricane, there might not be enough value left in the well to support the cost of repairing it. **In a way, these are highly leveraged investments; not *financial* leverage in the traditional sense of the word, but *leveraged with respect to replacement cost*.** In the case of the well whose production had fallen to 1,800 barrels per day, the platform's original construction cost was $1 billion. Even at an enhanced production rate of 5,000 barrels per day, the value of the oil comes nowhere near the level required to economically justify replacing or fixing it if it were seriously damaged. **Weather-related serendipity explains, as I see it, why outsized returns can be earned if everything goes according to plan: because the downside case cannot be easily hedged or insured away.**

II: *A Lighter Shade of Shale*: shale oil/natural gas liquids are worth a lot more than shale gas

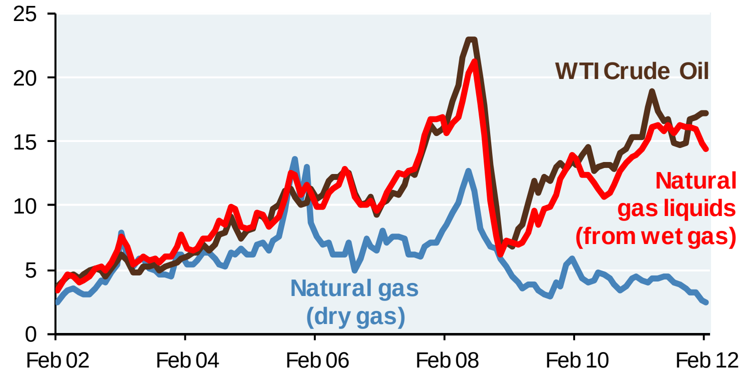
I am going to oversimplify for a minute, **so don't overreact**. But the best shale gas plays are the ones that involve finding liquids in addition to (or instead of) dry gas. Let me explain via the chart below, on the left. It shows the price for coal, natural gas and crude oil per unit of heat/energy. In a theoretical world, humans would stop using oil and gasoline and use more natural gas instead. But in the real world, oil and natural gas are not frictionless substitutes. One of my favorite graphics from the Energy Information Administration (http://205.254.135.7/totalenergy/) shows how oil is used primarily for transportation, whereas natural gas is used mostly by industry and to create electricity. There is a small subset of oil still used by industry (8% of total primary energy consumption), but the primary reason why US gasoline prices are so much higher than natural gas prices is that the US does not have a national fleet of natural gas vehicles. The obstacles to this are not insurmountable (see Appendix A), but I do not get the sense that an NGV fleet is imminent, even with very high gasoline prices.

Energy prices: a massive premium for crude
USD per mm BTU, 6-month moving average



Source: St. Louis Fed, EIA, Bloomberg, J.P. Morgan Private Bank.

Natural gas liquids valued like crude, not dry gas
USD per mm BTU



Source: Bloomberg, J.P. Morgan Securities LLC.

As a result, there is no substitution effect pulling up natural gas prices, particularly as more natural gas is being found in shale plays. **But for shale investors, there are liquids that can be found in shale plays that are worth a lot more than dry gas: shale oil, and natural gas liquids**. Shale *oil* obviously is valued based on oil prices, and natural gas *liquids* are valued close to oil prices as well (see second chart above). What are natural gas liquids? They come from "wet gas", which refers to the kind of natural gas that when exposed to "cryogenic" temperatures of -120 degrees F, partially condenses back into liquids such as ethane, butane, propane, etc, and methane (a gas). Natural gas liquids are mostly used as a chemical feedstock, and as non-grid fuel (crop-drying, rural heating, grilling). "Dry gas" is almost entirely methane (used mostly for electricity generation and fertilizers), and is too expensive to convert into liquid form (methane liquefies at -260 degrees F). The higher carbon molecules (ethane C_2H_6, propane C_3H_8, butane C_4H_{10}) are worth more than methane (CH_4) for two reasons: they convert into liquids at higher temperatures than methane, and generate more heat when burned.

***Reservoir Digs*: on energy investing and private equity**

With that lens, it's easier to understand the value creation in some recent transactions. A major gas company sold its interest in select shale fields in the Permian Basin in West Texas and Southeast New Mexico. The fields one of our managers purchased were made up of 31 million barrels of proven reserves whose current production is split 1/3 oil and 2/3 natural gas[5]. Based on the oil-gas price discrepancy described on the prior page, this manager plans to primarily reinvest in related shale oil opportunities, bringing the production mix closer to 50% oil and 50% dry gas, a more attractive proposition for a future buyer.

Perhaps one day, supply-demand equation will drive US natural gas prices higher; they are now ~$2.25 per mcf in the spot market, down from their $13 peak in 2008. A WSJ story today noted that the supply glut was so large, that storage space could be exhausted by the end of the year (as in 2009 when prices tumbled). **Could an export market help?** European natural gas prices are 5x-6x higher than US prices, but (a) there are no LNG export terminals in the US, although some are planned, (b) shipping costs for natural gas are 3x higher than oil (due to regasification/refrigeration costs and specialized ships), and (c) Europe appears to have plenty of shale gas as well, although development has been limited. As a result, the value of a US export market lay in the future. Another source of nat gas demand: **displacement of coal**. Since 1997, natural gas shares of US electricity generation rose by 10% while coal's share fell by the same amount; we expect another 30 GW of coal to go offline by 2017. However, this is a gradual process. Unfortunately for natural gas operators, there are 1,200 natural gas wells drilled every month, and mineral rights holders are anxious to earn royalties. However, **the news is not all bad for operators that only find dry gas**: there are means by which production can be postponed to another day. In some cases, wells can be drilled but not completed, and production on one site can sometimes be used to "hold" other undeveloped acreage without having to produce.

Other than normal operating risks, there is of course the broader issue of fracking, and what operational safeguards will need to be put in place to allay concerns about aquifers, earthquakes, etc. Eventually, the industry, regulators and Congress will triangulate to some kind of standard. All I can say is that if people had *any* idea about the long-run environmental costs associated with coal mining, natural gas would look tame in comparison. See Appendix B for a discussion about fracking and seismic risks I had with scientists from the Lamont-Doherty Earth Observatory.

III: No child left behind: enhanced oil recovery techniques

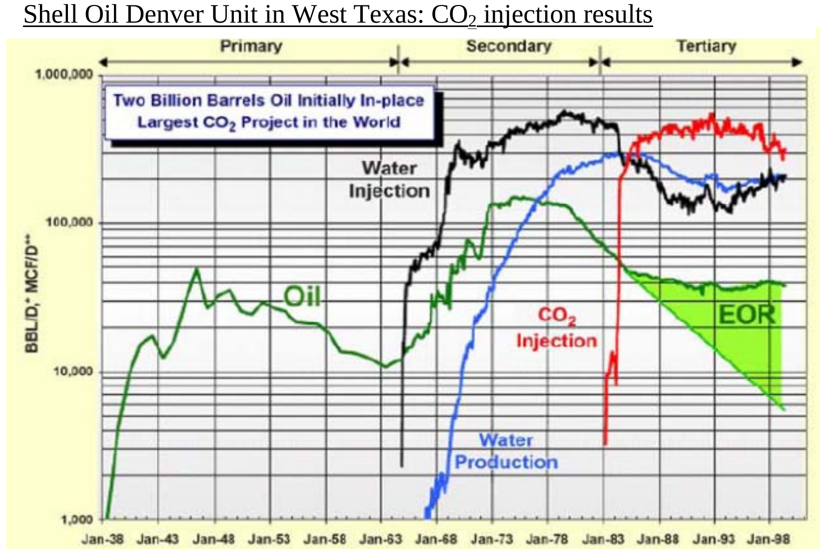
When oil was plentiful and when technology wasn't, the E&P industry was content to extract around 20% of the original oil in place in a given reservoir, using traditional extraction techniques. Now that oil is scarce and technology is plentiful, there's an economic incentive to spend money to get more oil out of the ground. Some petroleum scientists believe that recovery factors could double or triple after applying secondary and tertiary "enhanced oil recovery" (EOR) techniques. **To me, estimates in the table below look optimistic; recent experience runs closer to 45%-50% after tertiary measures.** There are EOR successes worth looking at in detail. The chart shows the results from the largest CO_2 injection project in the world, Shell's Denver Unit in Texas. By 1982, water injected and produced was more than the oil produced. When CO_2 injection began, the oil production decline leveled off. In 2010, the Denver Unit produced 31,500 barrels of oil per day, of which 26,000 was incremental and attributable to CO_2 injection (green wedge). EOR can be expensive, so there is a tradeoff between how much you spend, and how much more you get out of the ground. On a worldwide basis, just a 1% increase in global recovery factors would represent almost 90 billion barrels of oil, equivalent to roughly 3 years of production at current levels.

Potential Oil Recovery Efficiencies, % of original oil in place

Primary Methods		
Liquid and rock expansion		5%
Solution gas drive		20%
Gas cap expansion		30%
Gravity drainage		40%
Water influx		60%
Secondary Methods	**up to**	**70%**
Gas re-injection		
Water flooding		
Tertiary Methods	**up to**	**80%**
Thermal (Steam, Combustion, Hot water)		
Miscible (CO2, HC gases, N2, Flue gas)		
Chemical (Polymers, Surfactants)		

Source: "*Global Oil Reserves – Recovery Factors Leave Vast Target for EOR Technologies*", Oil & Gas Journal, November 2007, Rafael Sandrea

Shell Oil Denver Unit in West Texas: CO_2 injection results



[5] Barrels are reported as "barrels of oil equivalent" a measure used to combine oil and natural gas reserves in consistent energy terms, based on the heat released when burning them.

***Reservoir Digs*: on energy investing and private equity**

EOR in practice. One of our managers recently purchased 200,000 acres of oil-producing land in Alberta and Saskatchewan. The fields have been producing for 40 years, were generating 15,000 bpd and were never subjected to EOR techniques. Cumulative recovery to-date is 8%-9%, so there should be opportunities to get more oil out of the ground. *Oil viscosity* differs from field to field, and low viscosity oil responds better to EOR techniques, since it's less "thick". The transaction was priced assuming that most of the oil was high viscosity. So far, large pockets of low viscosity oil are helping the EOR efforts, and production has risen to 18,000 bpd. The managers believe that an eventual increase of 3x-5x the current production rate is a reasonable target; time will tell. These kinds of investments already entail a great degree of operating risk, so I find it reassuring when managers hedge most of their production.

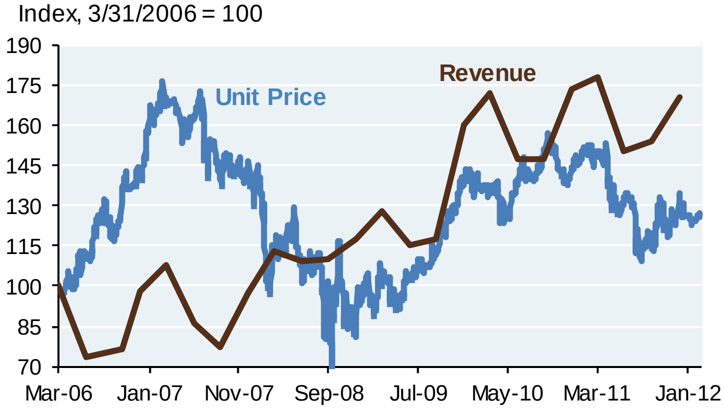
IV: Pipelines: slow, steady and boring (in a good way), assuming you can build them

The complicated part about energy is that you have to get it to where it's needed. One example of how important infrastructure is: in 2009, the American Society of Civil Engineers issued a report card which gave the US transmission grid a "D" grade, and put a $2 trillion price tag on upgrading it. This is one of the obstacles that solar and wind energy face, even if their capacity factors can be raised. With respect to hydrocarbons, as one example, consider the discrepancy between oil prices in Cushing, Oklahoma and other parts of the country. This is a reflection of the lack of adequate pipeline infrastructure to get surplus oil out of Cushing. As a result, well-placed infrastructure is a critical component of the overall energy supply chain.

The ideal end-game of pipeline development is a pipe whose use is guaranteed, even if the energy feedstock producer cannot produce it, or if the end user doesn't need it (a "take-or-pay" contract). As in commercial real estate, buying completed projects with long-term leases yields stable but lower returns; development yields higher returns, assuming the project is delivered on time and on budget. In theory, completed pipelines should offer stable returns to investment portfolios. However, their valuations can be volatile in the public markets. Sometimes this is more a reflection of nervous and overleveraged investors than of underlying business risk. Case in point: as shown below, a pure play MLP like Boardwalk Pipeline Partners experienced a 50% collapse in its unit price during the financial crisis, even though its revenues were steadily rising.

An example of a pure-play natural gas MLP

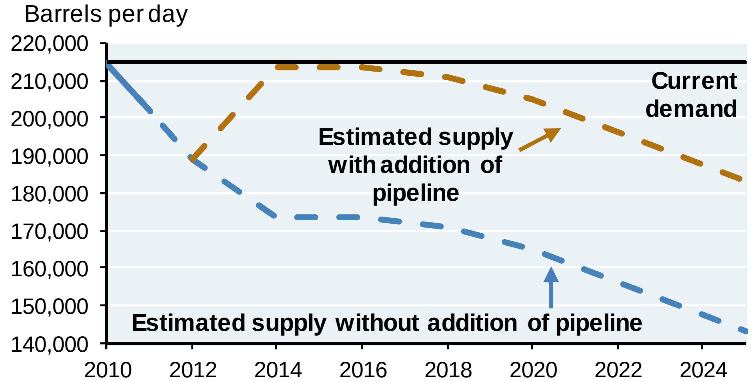
Index, 3/31/2006 = 100



Source: Bloomberg, Boardwalk Pipeline Partners.

Ethane supply in Western Canada

Barrels per day



Source: National Energy Board of Canada, North Dakota Public Service Commission, J.P. Morgan Private Bank.

Looking at an example: a planned US-Canadian ethane pipeline. Ethane is the lightest of the natural gas liquids, and is used to create plastics, clothes, resin, and a lot of the things on your desk. There's a large concentration of companies in Alberta which need ethane, and there's a wet gas basin in North Dakota that produces it, in the Williston Basin. As shown in the chart above (right), falling ethane supplies from existing sources in Western Canada have put the region into a supply deficit. Hence, the economic benefit of building a 430-mile pipeline from North Dakota to Alberta, powered by 500-horsepower pumping stations. The project in question has a maximum flow rate of 40,000 barrels of ethane per day, which can be expanded to 60,000 bpd if additional investments are made to add more pumping stations.

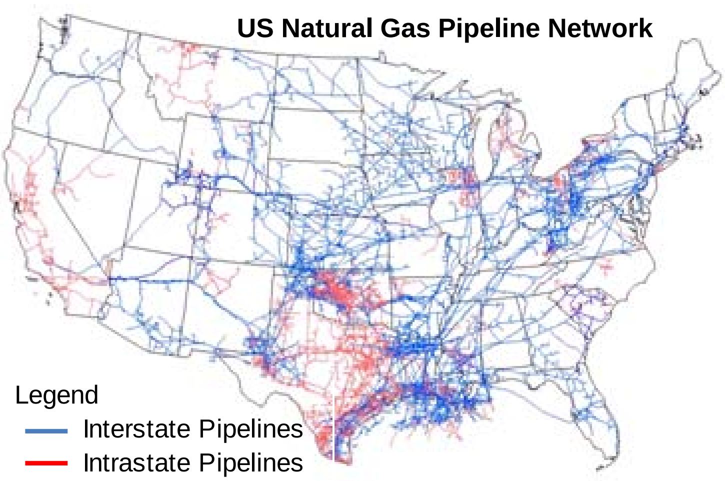
The economics for the pipeline developer are clear: complete the project, and reap the benefits of a 10-year, minimum volume, take-or-pay contract between the ethane shipper (e.g., the pipeline developer) and the consumer (e.g., a petrochemical company), the terms of which were finalized in Q1 2011. The consumer takes the risk of the ethane producer's ability to perform; the pipeline developer takes the credit risk of the ethane consumer, irrespective of the actual flow put through the pipeline. "Credit risk" is a bit different than in a real estate or corporate bond context; many energy facilities are so efficient and critical to the supply chain that consumers would continue to make their pipeline payments in almost any business environment. The contractual commitment by the ethane consumer in this case is for half the pipeline's volume, leaving the remainder available for additional contracts. The developer projects attractive returns just based on the initial take-or-pay contract.

***Reservoir Digs*: on energy investing and private equity**

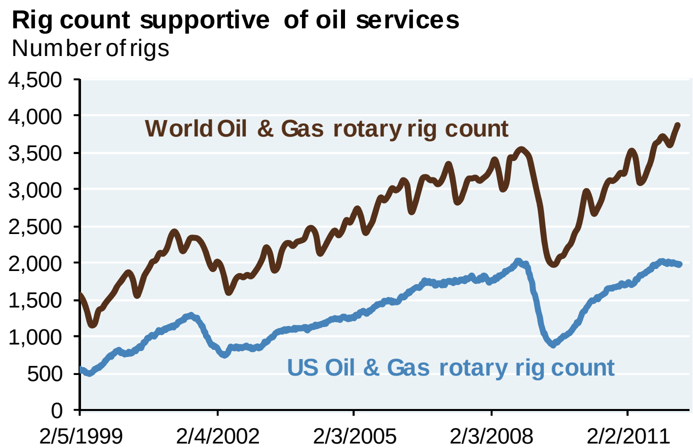
In general, pipelines can cost as little as 4x cash flow to build, and once operational and contracted, can be sold at 8x-10x cash flow. The challenging part is of course building it. In February of 2011, the developer submitted a regulatory application to Canada's National Energy Board for a certificate to construct and operate the pipeline. Construction is expected to begin following Canadian and US approval in mid-2012 with a targeted in-service date by mid-2013. As an example of what the pipeline developers contend with, consider the following, excerpted from an application submitted to the North Dakota Public Service Commission for this project, dated February 2012:

- Cease construction and contact US Fish and Wildlife Service if a whooping crane (specifically of the Aransas Wood Buffalo Population) is sighted within 1 mile of a pipeline or associated facilities
- Construction in areas within ¼ mile of a sharp-tailed grouse must not occur between March 1 to May 15 of any year or within 2 hours of sunrise on any given day; avoid documented and potential nesting wetlands for piping plover from April 1 through September 1

The point here is not to debate the cost/benefit of any set of provisions, but to understand the hurdles that must be overcome to get it approved and constructed. Natural gas pipeline development is not new; there are 305,000 miles of natural gas pipelines in the US (see map below), and this project would represent a 0.026% addition, given the 80 miles that are planned to be built in the US. While the approval process involving two countries can be cumbersome and take many months (or years), capital outlays during this part of the process are contained, mitigating the risks to the investor group.



Source: EIA. 2009.



Source: Bloomberg, Baker Hughes.

<u>**V: Equipment and oil services: some diamonds in the rough, but riskier than you might think**</u>

While it might seem less risky to invest in equipment and oil services, the sector has been much more volatile than Integrated Oils and E&P companies, and the entire market (see chart on page 2). One can speculate as to why; it probably has something to do with how quickly the majors scale back services demand when economic conditions slow down. In the long run, the rationale for some of these stocks remains in place: in the US and internationally, rig counts have been rising again. But the barriers to entry are not as high as in other energy related businesses, and both valuations and revenues can be very sensitive to the level of commodity prices. Things like oil & gas rig counts are interesting high-level ways of looking at services demand, but the reality for private equity investors is that their exposures in oil services tend to be highly concentrated. Results can vary widely from company to company, reducing the benefit of broad generalizations about services demand.

There appears to be a substantial difference between production services, midstream services and exploration services. The first two sustain demand even when new wells aren't being drilled. But even in production and midstream services, there have been some well-known underperformers among public companies, such as Exterran, Tetra and Helix. Exterran is interesting, since natural gas compression services is where one of our managers recently made an investment, in a competing company. The investment rationale is that as long as dry gas prices remain low, most operators would rather lease this equipment than buy. Even though they are cost-sensitive, natural gas operators are also looking for the most powerful compression equipment to be able to handle the enormous flood of shale gas they are developing. The company one of our managers recapitalized has the most powerful equipment in the industry, and is not burdened with lower-margin fabrication and marketing businesses. As a result, their current operating margins are above 50%. But like most investments in the services industry, managing the cycle is critical in generating positive returns, since little can be done to hedge away the inherent volatility of the business model. A dedicated energy investor's long term track record tells you a lot about how successful they have been at navigating the opportunities and pitfalls of investing in oil and equipment services.

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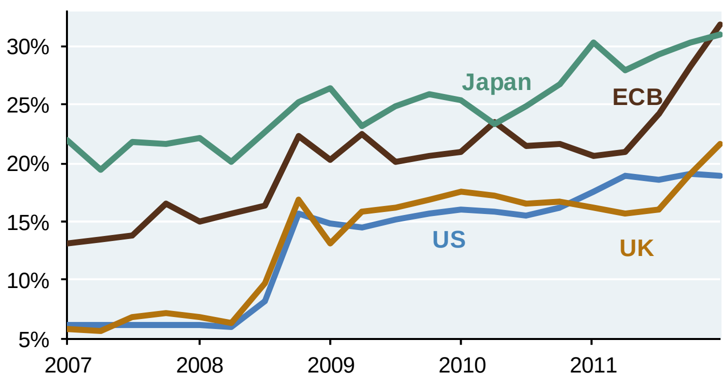
Conclusions

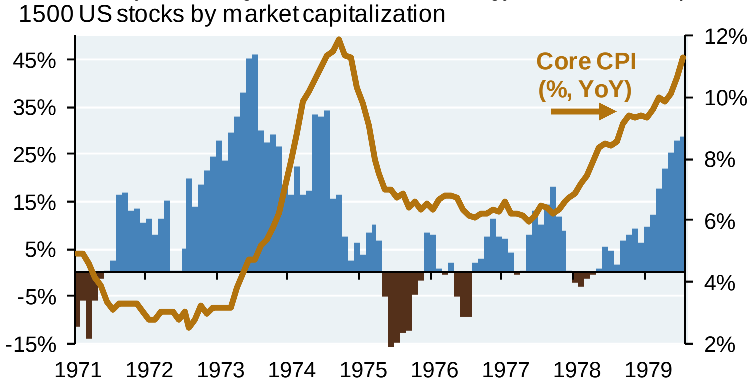
Investing in energy companies, whether via public or private markets, starts with cash flow valuations *and* projections, GDP growth assumptions and supply-demand expectations for fossil fuels. What is tricky now is the added question of whether Central Banks have a not-so-secret plan to generate higher inflation, their denials notwithstanding. US core inflation has fully reversed the decline following the financial crisis and is now back at its 15-year average. Still, the Federal Reserve and other central banks are running extremely easy monetary policy. Bernanke and his counterparts in other countries indicate that they will definitely take the punch bowl away when the time comes, and not accept wage or goods price inflation in excess of their targets. We have no way of knowing if they really mean this. In this regard, energy investing appears to be a partial hedge against policymakers accepting more inflation in exchange for higher growth, more job creation, and a reduction in the real value of government and household debt. As shown below, during the 1970s, energy outperformed the market by a wide margin. The energy sector will most likely retain its well-advertised sensitivity to global growth, operational and environmental challenges and political risks; we have found that such risks have been worth bearing in exchange for the returns.

Central bank balance sheets: ECB #winning
Percent of GDP



Source: FRB, BEA, ECB, Eurostat, BoE, UK Office for National Statistics, BoJ, Japan Cabinet Office.

Energy outperformed during the inflationary 1970's
Percent, 2-year rolling relative return of energy stocks to the top 1500 US stocks by market capitalization



Source: Morgan Stanley, Bureau of Labor Statistics.

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Appendix A: Natural gas is everywhere. Why don't we use it to drive?

The Potential Gas Committee in 2008 estimated that the US has 90 years of natural gas supply, and that's without including methane hydrates (gas trapped in frozen water) and biogas (landfills). Why not promote compressed natural gas cars? The energy costs would be lower than gasoline, even after taking into account higher CNG processing costs. The fuel economy benefits appear to be negligible, but emissions benefits (CO, CO_2, N_2O) would be substantial. The National Academy of Sciences **loves the idea**: "*With further expected improvements in vehicle technology and fuel efficiency, natural gas powered vehicles will provide superior benefits in terms of criteria pollutant reductions compared to nearly all other types of vehicles, even electric and plug-in hybrid electric vehicles.*" Argentina, Pakistan, Brazil, Italy and India are the heaviest users of natural gas vehicles (NGVs). The US accounts for 100,000 out of a global 13 million, and ranks 39th in the world in per capita NGVs.

Adoption by truck and bus fleets may speed up given low natural gas prices. However, it may take a lot of public policy (e.g., large tax credits) to alter the entrenched infrastructure and cost advantages of US gasoline cars (light duty vehicles):

Expense: the 2010 Honda Civic GX (an NGV) cost $6,800 more than the comparable gasoline-powered Civic, although this issue may be premature to evaluate when NGVs do not benefit from economies of scale. Based on its current higher price, the Honda Civic GX would have a ~20 year payback period (the time it would take for the higher vehicle price to be offset by fuel cost savings). Last year, Congressman John Sullivan (R-OK) introduced the "*New Alternative Transportation to Give Americans Solutions Act*", which offers an 80 percent income tax credit for the incremental cost of dedicated NGVs and a 50 percent income tax credit for the incremental cost of bi-fuel NGVs. If passed, payback periods could fall to 3-4 years.

Convenience: loss of half the trunk space in some NGV models, and 2/3 the driving range per tank compared to gasoline cars.

Limited refueling infrastructure: Currently, the number of NGV fueling stations is less than 1% of the number of gasoline stations. As an alternative, NGV owners could refuel at home using natural gas compression kits costing around $5,000.

Other oddities: temperature issues and other factors result in some users not being able to achieve more than an 80% fill of the NGV tank. The fuel gauge can also be inaccurate, overestimating the amount of fuel left in the tank.

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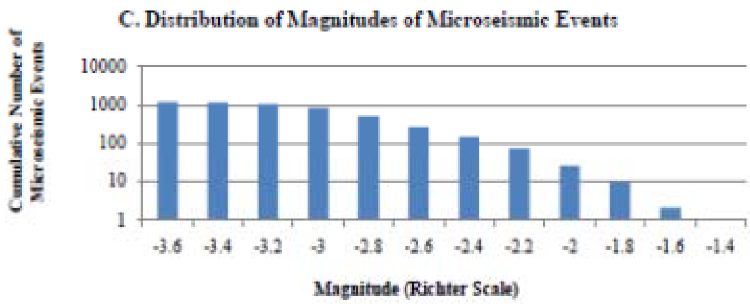
Appendix B: natural gas fracking and seismic risks

I am on the board of the Lamont-Doherty Earth Observatory, and this month, we had a session with 3 Lamont scientists on the subject of fracking and seismic risks. The session's participants included experts from seismic geology, tectonophysics and marine geophysics. The most important conclusions from this discussion, at least from my perspective:



- When multi-stage hydraulic fracturing is performed, the induced microearthquakes generated during each stage are so small they can be detected only using highly sensitive seismometers placed in nearby monitoring wells. The range of outcomes from fracking in the Barnett shale have registered *negative* readings on the Richter scale (negative, since it's a log scale).
- There have been larger seismic events that appear related to fracking activities in Ohio, Texas, Colorado, Arkansas and Oklahoma, the latter sustaining a 5.7 quake last fall. **However, these seismic events appear associated with the *re-injection* of fracking fluid after it has been used to surface shale gas, not the fracking itself**. The reinjection of fracking fluid does not have to take place in the same location as the fracking activity, providing operators with the opportunity to learn over time how to select spots that are less seismically at risk. *Note*: Pennsylvania trucks its fracking fluid out of state; some Ohio earthquakes appear to have been caused by reinjection of fluids from Pennsylvania fracking.
- It takes a sustained level of pressure over a sustained period of time to generate a seismic event. As the industry learns more about seismic risk, operators may slow the flow rate of re-injection. Experiments conducted in Rangely, California show that seismic activity is highly sensitive to reservoir pressure from re-injection.
- Fracking generally takes place 4,000 to 8,500 feet below the surface, while the deepest sources of drinking water are 850 feet below the surface (half a mile of rock separate them). The greater risk to groundwater supplies: a failure of the cement surrounding the wellbore itself, and contamination of groundwater from accidents during transport, storage and disposal of fracking fluids and waste water (which can contain naturally occurring salts, radioactive material, arsenic, benzene and mercury). Treatment facilities may eventually be the answer if there not enough reinjection wells naturally available.

Sources

"*Carbon Dioxide Enhanced Oil Recovery: Untapped Domestic Energy Supply and Long Term Carbon Storage Solution*", National Energy Technology Laboratory, US Department of Energy, March 2010

"*Assessing the viability of compressed natural gas as a transportation fuel for light-duty vehicles in the United States*", University of Texas/Austin, August 2011

"*Addressing the environmental risks from shale gas development*", July 2010, Worldwatch Institute, Zoback et al.

Acronyms

BTU = British thermal unit; CNG = compressed natural gas; E&P = exploration and production; EIA = Energy Information Administration; EOR = enhanced oil recovery; GW = gigawatts; IPO = initial public offering; LNG = liquefied natural gas; MCF = million cubic feet; MLP = master limited partnership; NGV = natural gas vehicle; OECD = Organization for Economic Cooperation and Development