

Equities

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Oil & Gas Equipment

Strong Secular Drivers Shine Amid Increasingly Choppy Macros

■ Industry Overview

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- **Highlighting Favorable Global Industry Trends** — A confluence of factors, including energy demand growth fueled by emerging markets, increasing dependence on more complex hydrocarbon reserves, and related infrastructure build-out help to create a compelling long-term secular growth story for engine OEMs. We see the greatest upside for CAT, given its dominant (global) position and superior ROA Oil & Gas portfolio, followed by CMI as it expands beyond its current leading position in the NA well-servicing market. Still, implications from increased energy investment and gas market proliferation are likely to be felt in some way across our entire coverage group.
- **All Hail the Shale...** — A fundamental shift in the U.S. natural gas industry propelled by the use of horizontal drilling combined with hydraulic fracturing has created a significant opportunity for OEMs and suppliers. These advanced drilling and production techniques are significantly more horsepower-intensive than traditional onshore E&P applications, and are still evolving, evidenced by per well fracturing HP in certain major shale plays that have more than doubled in just two years. Since 2006, total U.S. fracturing horsepower has grown at greater than 25% per annum and the continuing trend in increased lateral length combined with the growing backlog of drilled, but not completed wells (~3,500), is supportive of a favorable (profitable) growth outlook. Separately, we highlight the break down in relationship between gas prices and the U.S. rig count, with essentially no correlation between the horizontal rig count (now ~70% of U.S. gas drilling) and trailing gas price over the past 7-plus years.
- **...Not Only in NA** — With known international shale gas reserves roughly 5x that of the US, we see significant longer-term potential should other regions embrace unconventional drilling. China, for example, emphasized development of shale gas in its 12th Five Year Plan, and recently held its first auction of reserves. Separately, recall that CNOOC has made two investments in US shale assets. In an attempt to quantify the potential \$ opportunity, we used the US frac rig as a rough guide and came up with a midpoint estimate for the total international frac engine opportunity (ex aftermarket sales) to be upwards of US\$20BB – a huge opportunity, especially as CAT and CMI expand global manufacturing footprints (and distributor capabilities in the case of CMI).
- **Offshore Growth** — Maturation of shallow offshore fields is driving E&P activities into deeper waters, and is accompanied by an increase in average drilling depth and well complexity, both of which require more powerful drilling and production vessels. HAL expects the average deepwater drill depth to increase by 20-25% over the next three years. We estimate the potential engine/turbine sales for rigs currently under construction to be more than \$3.6 billion, while each floating production vessel represents up to \$100 million opportunity for engine and turbine OEMs.
- **What Are Some Key Risks** — Besides the obvious risk that further macro weakness weighs more heavily on energy prices (and E&P capex), our checks suggest that electric motors (used to drive compression units) are gaining share in the US. With energy regulations increasing, and more oil and gas deposits being discovered in less remote areas (with greater grid access, and less tolerant of noise), net/net this favors electric motor drives over turbines and recip – something worth watching longer-term.

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

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Oil and Gas Equipment Overview

While recent economic softening has muddled the near term outlook somewhat for energy prices and E&P capex, the longer term outlook for OEMs manufacturing power solutions for the oil and gas industry remains attractive. As the contribution from conventional hydrocarbon reserves declines as a percentage of total global production, it is being replaced by energy sources that are increasingly difficult to access and develop. This increasing complexity results in the need for higher horsepower, more durable engines and equipment throughout the exploration and production process, which is a positive for our coverage companies due to the direct relationship between horsepower and profitability. This report highlights some of the power solutions and related products our companies produce for the oil and gas industry as well as outline how changes in the industry, such as the development of shale plays, are driving growth of larger HP solutions. The names in our coverage list that we see as biggest beneficiaries of these trends are Hold-rated CAT and Buy-rated CMI.t

A Global, Still-Evolving Market, With Diverse Competitive Structures

The equipment needs for the broader Energy segment are wide-reaching, and have grown to meaningful levels for some companies that investors do not instinctively think of as Oil & Gas component suppliers (e.g. Parker Hannifin's +\$500MM of sales exposure).

The companies we cover sell a wide range of products and services for up, mid and downstream oil and gas activities. While this report focuses most heavily on the relevant reciprocating engine and turbine operations of CAT and Cummins, it is important to note that every company in our coverage list has some degree of exposure to this wide-reaching (and in some cases still evolving) segment. Illustrated by the random examples ranging from hydraulic pumps made by Parker Hannifin that drive motors on a drill rig, to electrical distribution and control systems from Eaton used on an off-shore oil rig, to a Paccar-made service truck used at a shale gas well (potentially fueled by a liquefied form of the gas being developed), to fully cover the "addressable market" of this industry is well beyond scope of this report. In fact, as we address in the section on Pipeline investment, even some equipment types that get classified in other segments such as Construction (i.e. tractors and hydraulic excavators used in grading and clean-up on pipeline projects) or Rail (used to transport oil from the Bakken Shale) are affected by changes in broader oil and gas activity. That said, we think this note will help to identify some of the broader trends that we see impacting these companies.

The following chart outlines some of the larger OEMs that manufacture the various products discussed in this report. As explained throughout the various sections, each company tends to have its relative strengths and market focus, with no player serving as the broad "industry" leader across all product categories. Also, this is obviously a global market, so solely focusing on trends in the domestic North American market ignores meaningful various regional dynamics. It is also important to note that each of the broad categories provided below can be further refined, and that the OEMs competing in the product categories may not compete in all of the subsections.

Figure 1. Select Competitor Overview

	Reciprocating Engines			Transmissions	Gas Turbines & Compressors		
	Onshore Drilling	Offshore Drilling	Well Servicing		Mechanical Drive	Natural Gas Engines	Centrifugal Compressor
Caterpillar	X	X	X	X	X	X	X
Cummins	X	X	X	X		X	X
Allison				X			
Dresser Rand					X		X
GE			X		X	X	X
Kato		X					
MAN Turbo & Diesel		X					
MTU Detroit Diesel (Tognum) ⁽¹⁾	X	X	X				
Rolls Royce		X					
Siemens					X		X
Twin Disc				X			
Wartsila		X				X	

Source: Company Reports

Investment activity has ramped-up significantly in the U.S. as global companies look to gain access to shale reserves. We have also seen M&A activity pick-up as engine manufacturers look to broaden their portfolios and technological competencies.

Just as there has been increasing activity and massive investment on the part of energy / diversified mining companies looking to gain access, or expand to, shale gas properties in the US (BHP's acquisition of Petrohawk a recent example), we have also seen equipment companies pursue M&A as well as internal investment to enhance their product portfolio to better capture changes in the global energy markets. GE Energy (covered by Deane Dray) has made several investments to expand its product portfolio for offshore production, as well as to add flexible fuel technology to its engines (acquired through its acquisition of Dresser). Though smaller in size compared to its headline-grabbing Bucyrus acquisition, CAT has announced two recent deals (EMD and MWM) which will help to grow its Engine portfolio and consequently expand its overlap with GE. The company's announced - but not yet closed - acquisition of MWM will help by providing flexible fuel (natural gas, biogas, mine gas, etc) technology that is gaining traction in power generation markets, especially given low natural gas costs as well as tighter environmental scrutiny. Dresser Rand's acquisition of Grupo Guascor provides it with diesel and gas engine technology so the company can offer packaged compressor solutions consisting of both the engine and compressor instead of packaging its compressor with a third party engine.

Cummins has stated its intentions of going the "build" versus "buy" route. The company is undergoing a significant investment program (\$300 million) to expand capacity at its Seymour, IN plant that will increase its horsepower range and enable it to better compete in segments of the O&G markets that its power range has precluded it from competing in the past. In addition, like CAT and GE, Cummins' investment also involves expansion of engine capacity with flexible (dual) fuel (i.e. diesel and natural gas) capabilities, though as mentioned above, it is pursuing an internally-developed approach. As we discuss in the report in greater detail, the increasing availability of gas produced in the U.S. thanks to the development of unconventional gas basins will likely have ramifications on equipment demand, as well as fuel type consumption.

Figure 2. Select Recently-Announced M&A Deals

Date	Buyer	Target	Acquisition Rationale
10/22/2010	Caterpillar	MWM	Adds flexible fuel engine technology.
6/1/2010	Caterpillar	EMD	EMD manufactures and sells diesel-electric locomotives and diesel power engines
5/17/2011	Rolls Royce / Daimler	Tognum	Expand presence in industrial diesel engines.
10/6/2010	GE	Dresser, Inc (Waukesha)	Adds position in small-scale compression, monitoring and diagnostics, and highly engineered valves. Also adds flexible fuel engine technology.
12/13/2010	GE	Wellstream	Adds flexible pipe capabilities for offshore oil production.
2/14/2011	GE	John Wood Group Businesses	Electrical submersible pumps for enhanced oil recovery and pressure control valves for fracturing.
3/3/2011	Dresser Rand	Grupo Guascor	Adds diesel and gas engine technology.
8/31/2011	Cameron	LeTourneau	Cameron acquired LeTourneau for its technology, which should allow to sell complete drilling kits, similar to NOV.

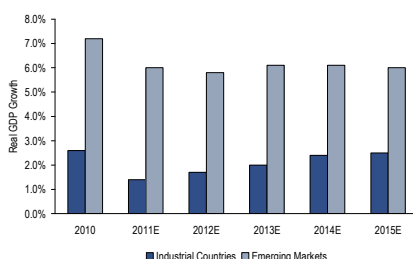
Source: Company Reports.

Current Market Conditions / Growth Drivers

Medium-Term Economic / Energy Price Outlook

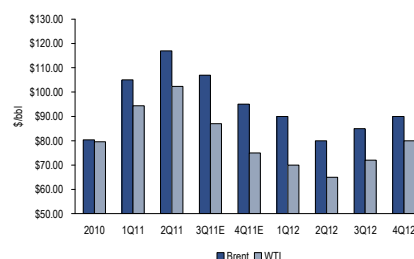
Changes in economic growth (GDP) are the main determining factor for changes in energy demand, with growth in energy output historically running about 2.3% below the rate of global GDP. With the expected softening of global economic conditions in the second half of 2011 and into 2012, as reflected by Citi economists' recent downgrade of the 2011 and 2012 GDP forecasts, the near term outlook for oil and gas demand, and therefore prices, has been notched downward. Based on the combination of lower global economic growth and increased OPEC and non-OPEC production, Citi's commodities research team recently lowered its Brent and WTI oil price forecasts for 2012 to \$86 and \$72 per barrel, respectively. This compares to current front-month futures prices of ~\$112 and \$87 per barrel, respectively.

Figure 3. GDP Forecast



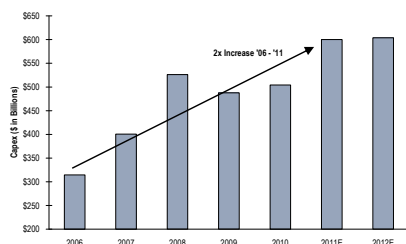
Source: Citi Investment Research and Analysis

Figure 4. Oil Price Forecast



Source: Citi Investment Research and Analysis

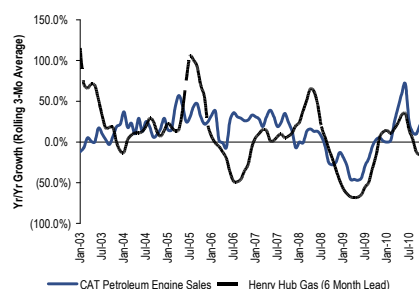
Figure 5. Global E&P Capex



Source: Citi Investment Research and Analysis

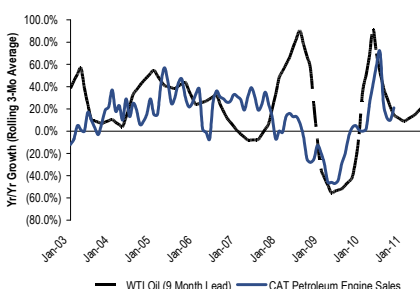
The price of hydrocarbons is obviously a key variable impacting E&P budgets, which is a key demand driver for the power solutions sold by our coverage companies. Following on from these latest oil price forecast revisions, CIRA's global Oil and Gas equity research teams still expect aggregate global E&P capex to grow by almost 20% year-over-year in 2011, before leveling off in 2012. Keep in mind that projected 2012 capital spending totals represent a doubling of expenditures versus 2006 levels. To better highlight the intuitive relationship existing between energy prices and broader equipment (in this case reciprocating engines) sales, the chart below shows rolling 3-month CAT dealer sales of engines sold to energy applications versus spot energy values. This analysis suggests that oil and gas price changes lead that of CAT retail sales by an average of roughly six months, dependent on the commodity price being analyzed. Correlations have also been much tighter during the 2008-2011 period that has coincided with increased hydrocarbon price volatility.

Figure 6. CAT Petroleum Engine Sales vs. Henry Hub Gas Price



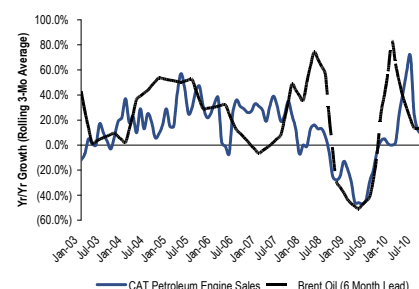
Source: Company Reports and CIRA

Figure 7. CAT Petroleum Engine Sales vs. WTI Oil Price



Source: Company Reports and CIRA

Figure 8. CAT Petroleum Engine Sales vs. Brent Crude Price



Source: Company Reports and CIRA

Accessing and developing increasingly complex global reserves requires higher horsepower needs. Coupled with high levels of aftermarket parts and service support necessitated by the extreme wear and tear of operations, we see an attractive (higher-margin) growth opportunity.

Long-Term Secular Drivers Help Frame Positive Outlook

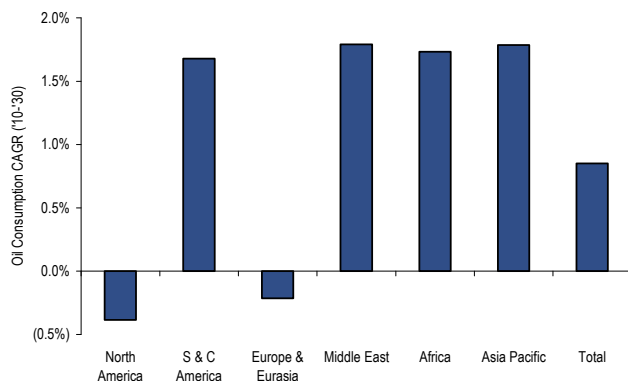
Clearly, in the current environment of heightened global economic volatility and uncertainty, we do acknowledge that downside risks for oil and gas equipment demand have increased. That said, even with energy prices at the full-year average level that CIRA forecasts for 2012 (which, in the case of oil, are below current spot levels), our discussions with industry contacts and colleagues in the oilfield services team suggest that +\$70/barrel (WTI) oil would still be high enough to justify a robust overall level of investment activity. Furthermore, looking beyond short-term volatility, we point to several secular trends that we think help underpin a positive longer term outlook for power solutions to the oil and gas industry. As discussed in greater detail below, this includes growth in global energy demand driven by emerging market development, and increasing dependence on more complex hydrocarbon reserves. Importantly, accessing and developing these more complex reservoirs requires higher horsepower due to the advanced techniques involved in drilling and production. Combined with the high service, 24/7 nature of certain operations, and resultant extreme wear-and-tear endured by the equipment, we see this helping drive a more attractive (i.e. higher margin) mix of equipment sales for the Machinery providers. In addition, significant infrastructure investment will be required to facilitate the control and transport of hydrocarbons from the well head to the consumer, driving greater need for equipment that extends beyond the traditionally-defined energy equipment market (i.e. pipelayers, excavators, rail equipment, etc).

Growing Global Energy Demand

The rapid development of emerging market economies (particularly China) is driving increased global demand for hydrocarbons. We would expect this trend to continue, especially based on CIRA's global economic forecast (see Figure 3 above) which in 2012 incorporates a growth rate for "Emerging Markets" that is roughly three-times higher than that of "Industrial Countries." As a point of reference, in 2000 U.S. oil consumption was ~4x larger than China's. As a result of the strong growth in Chinese consumption that occurred over the next decade, U.S. consumption is now only 2x that of China's. China spent \$40BB acquiring global energy assets in 2010.

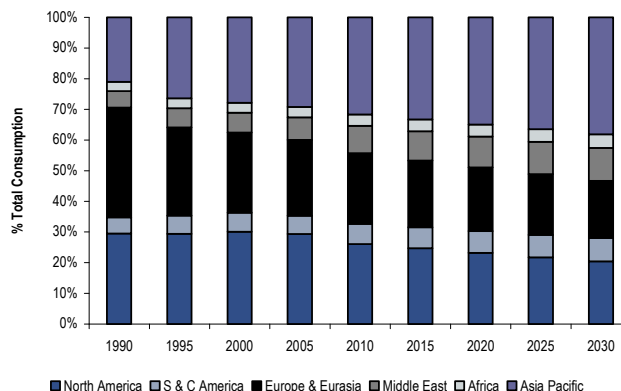
Based on BP's 2011 Statistical Review, emerging market development is expected to continue to be the primary driver of global oil demand growth, which is projected to more an offset the expected plateau and decline forecast to occur in the developed markets of North America and Europe.

Figure 9. Oil Consumption CAGR ('10 - '30)



Source: BP Statistical Review 2011

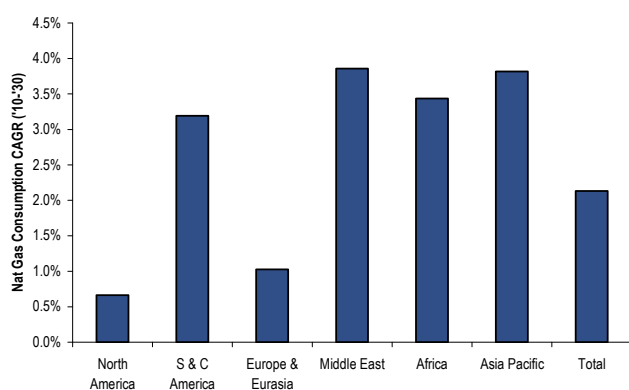
Figure 10. Oil Consumption by Geography



Source: BP Statistical Review 2011

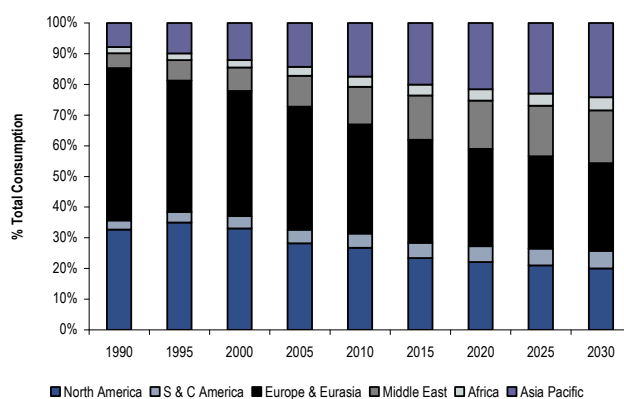
Growth in demand for natural gas is also expected to be driven by emerging markets. However, developed market natural gas demand, unlike for oil, is also expected to grow. This is partially explained by increasing environmental concerns and the desire to transition from coal based power generation. The recent nuclear accident in Japan has also contributed to expectations for growing natural gas demand as several countries (most notably Germany) have responded to the accident by ending their use of nuclear power plants. In addition to decommissioning existing nuclear plants, there is also growing uncertainty regarding the likelihood of constructing new nuclear power plants that were in development prior to the Fukushima accident. If these plants are not commissioned, natural gas fired power generation is the logical substitute.

Figure 11. Natural Gas Consumption CAGR ('10 - '30)



Source: BP Statistical Review 2011

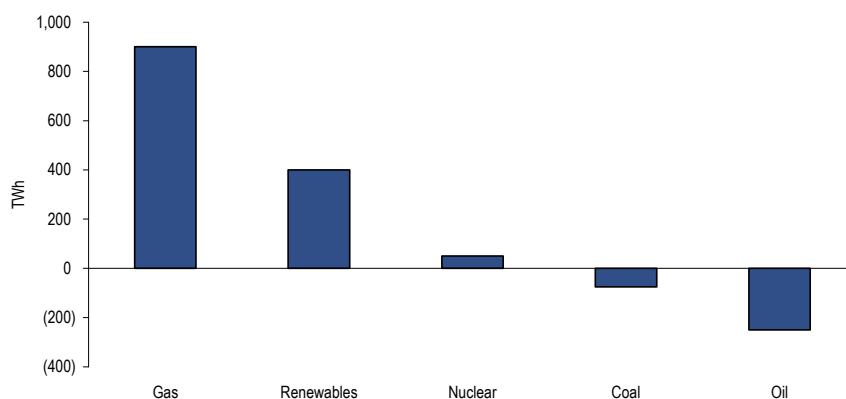
Figure 12. Natural Gas Consumption by Geography



Source: BP Statistical Review 2011

The increasing dependence on gas for power generation was clearly evident during the last decade, with about 90% of net additional power generation capacity coming from natural gas.

Figure 13. OECD Incremental Power Generation, 2000 - 2010



Source: IEA

Figure 14. Supergiant Oilfields

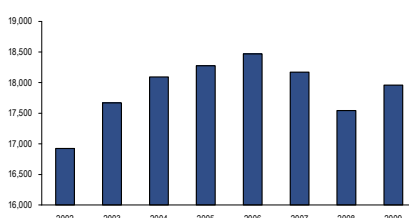
Field Name	Country	Discovery Year
Bolivar Coastal	Venezuela	1917
Kirkuk	Iraq	1927
Gashsaran	Iraq	1928
Agha Jari	Iran	1937
Burgan Greater	Kuwait	1938
Abqaiq	Saudi Arabia	1941
Ghawar	Saudi Arabia	1948
Safaniya	Saudi Arabia	1951
Rumaila N&S	Iraq	1953
Manifa	Saudi Arabia	1957
Ahwaz	Iran	1958
Samotlor	Russia	1961
Marun	Iran	1963
Berri	Saudi Arabia	1964
Zakum	Abu Dhabi	1964
Zuluf	Saudi Arabia	1965
Prudhoe Bay	Alaska	1969
Cantarell Complex	Mexico	1976

Source: AAPG, EIA, and OGI

Increasing Dependence on Unconventional / Complex Reserves

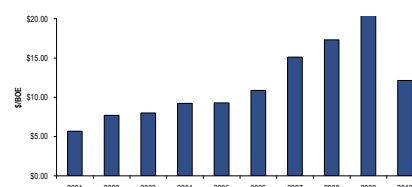
The growth in demand stemming from emerging market development is occurring during a time when the oil industry is struggling to replace existing sources of production. The last discovery of a large conventional (easy to develop) oil field occurred 35 years ago, and the combined oil production for the ten largest International Oil Companies (IOC's) peaked in 2006. Furthermore, fully loaded finding and development costs have increased by a factor of 4x over the past decade.

Figure 15. Total Oil Production – IOCs



Source: Petroleum Review

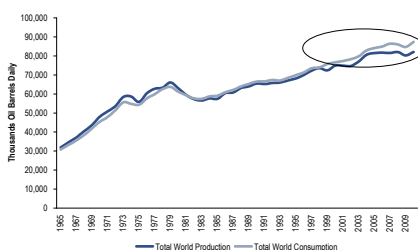
Figure 16. Fully Loaded Finding & Development Costs - Independents (\$/BOE)



Source: Citi Investment Research and Analysis

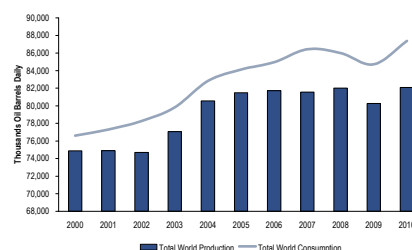
The oil industry's struggle to meet growing global demand is evident in the following chart that demonstrates the increasing divergence between oil consumption and production that occurred over the past decade. In turn, during this period oil prices broke from their 30 year plus price range and reached price levels that were roughly triple that of their previous high.

Figure 17. Global Oil Production & consumption (1965 – 2010)



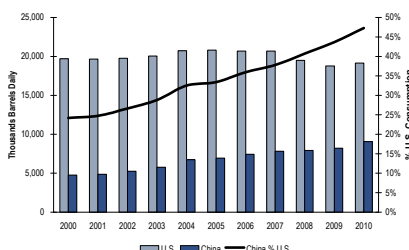
Source: BP Statistical Review 2011

Figure 18. Global Oil Production & consumption (2000 – 2010)



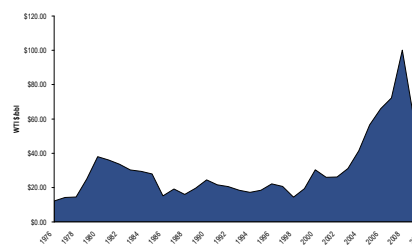
Source: BP Statistical Review 2011

Figure 19. U.S. vs. China Oil Consumption



Source: BP Statistical Review 2011

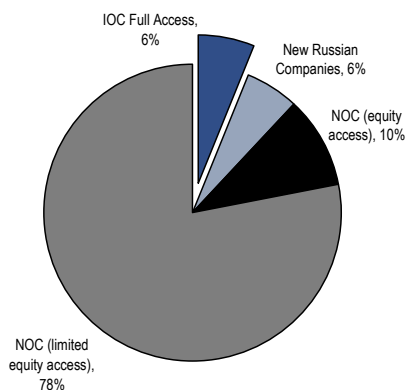
Figure 20. Per Barrel Price of Oil (WTI)



Source: BP Statistical Review 2011

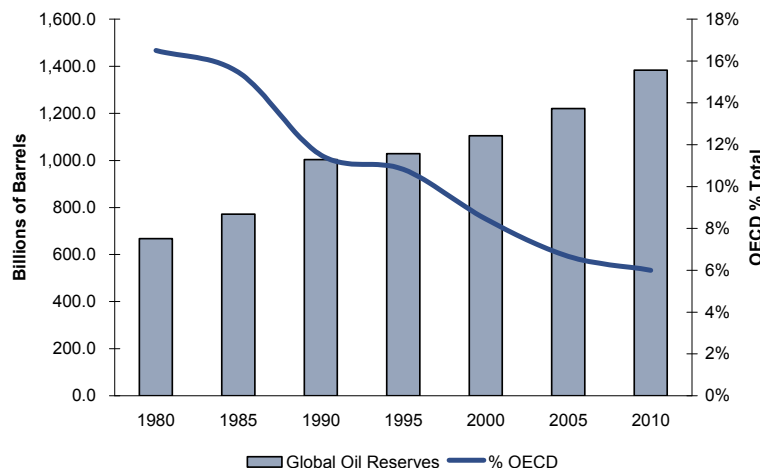
The increasing nationalization of oil resources is another factor limiting development of new sources of oil supply. In 1980, the IOCs had full access to ~17% of the global oil reserves, but this number has declined to just ~6% today as resource rich countries have increasingly limited IOC access.

Figure 21. IOC Accessible Oil Reserves



Source: EIA

Figure 22. OECD Oil Reserves



Source: BP Statistical Review 2011

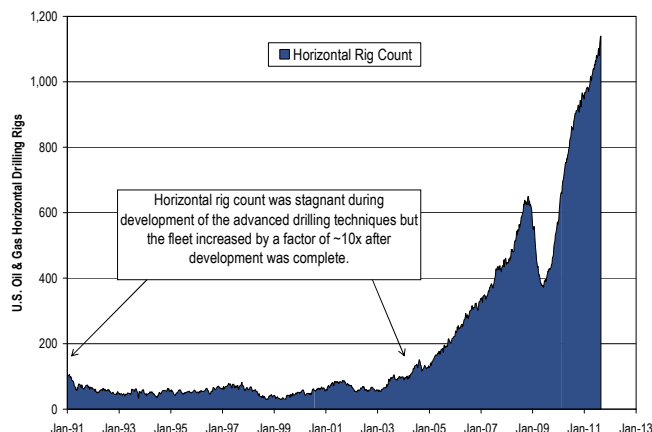
In response to these factors, IOCs are increasingly exploring hydrocarbon resources that are more difficult to access and develop. The declining supply of conventional onshore hydrocarbon reserves spurred advancement in drilling and production technologies, including horizontal drilling and hydraulic fracturing stimulation, which has unlocked vast amounts of previously inaccessible hydrocarbons located in shale deposits. Similarly, offshore production is being forced to explore increasingly complex sources of hydrocarbons with operating depths now in excess of 10,000 feet. As we will discuss in the following sections, this increased complexity associated with finding and developing onshore and offshore hydrocarbons is creating growing demand for larger (more profitable) power solutions.

Onshore Shale / Unconventional Drilling

A fundamental shift has occurred in the U.S. natural gas industry as the use of horizontal drilling combined with hydraulic fracturing has driven major production gains and improved economics for producers to exploit shale formations.

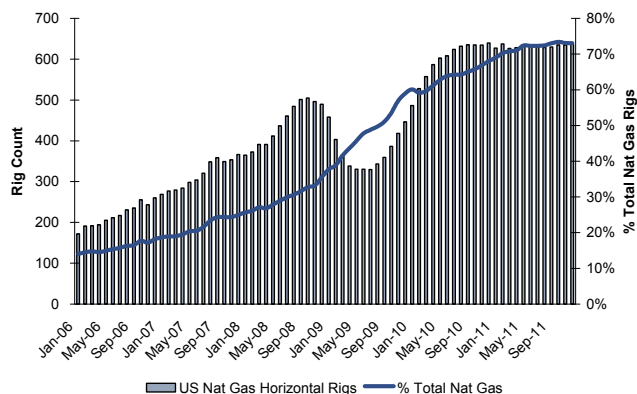
As recently as 2005, the accepted view was that the U.S. would become a major importer of natural gas as its growing demand was confronted with dwindling supplies. However, technological advancements in drilling and production have unlocked vast supplies of gas reserves trapped in shale deposits and other tight gas reservoirs. This is largely the result of many years of experimentation from a number of domestic E&P companies who looked for ways to perfect horizontal drilling as a means to unlock the potential of tight gas reservoirs. This had actually been in use in the oil industry as far back as the 1970's, but meaningful improvements in the 1990's. After more than a decade of testing in the Barnett Shale in the Forth Worth Basin, by the 2004/2005 period the E&P and oil service companies had developed the techniques and acquired sufficient geologic knowledge needed to develop and produce shale gas economically (even at relatively low gas prices). With this experience behind it, the industry raced to identify other gas-bearing shale reservoirs that could be developed, and introduced aggressive acreage leasing programs in new plays such as the Haynesville Shale in Louisiana and the Marcellus Shale in Pennsylvania. Demand for high efficiency horizontal rigs exploded; the horizontal rig count has increased nearly ten-fold since 2005. For onshore U.S. natural gas drilling, more than 70% of the U.S. rig fleet now consists of horizontal drill rigs.

Figure 23. U.S. Horizontal Rig Count



Source: Baker Hughes and Citi Investment Research and Analysis

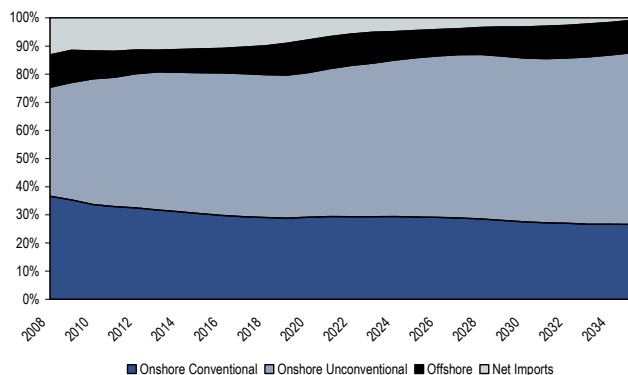
Figure 24. US Horizontal Natural Gas Drilling Rigs



Source: Baker Hughes and Citi Investment Research and Analysis

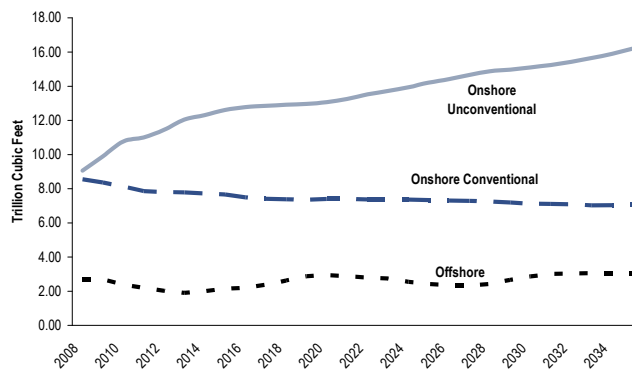
The result has been a sort of renaissance for the US gas industry: while having accounted for just over 20% of U.S. production in the 1990's, gas from onshore unconventional basins is estimated by the Energy Information Administration (EIA) to account for 54% of U.S. gas production in the current decade.

Figure 25. Historical and Forecast Natural Gas by Source



Source: EIA

Figure 26. Historical and Forecast Natural Gas Production



Source: EIA

So, what does this mean for equipment manufacturers and engine providers? Power requirements vary greatly with the geography and type of well being drilled. For example, a small mobile drilling rig operating at a low depth can run on as low as 500 to 600 horsepower, whereas a large land rig designed for unconventional plays with horizontal drilling capability can take up to 7,500hp. As such, we think the trend towards drilling longer and deeper horizontal well versus conventional (vertical) drilling activity could be a significant positive potential catalyst for engine OEMs, as engine profitability is typically directly related with horsepower. Furthermore, new rig designs have significantly better productivity than older models, and as a result, the percentage of time the rigs are actively operating has increased. We see this as a potential driver of greater aftermarket revenue opportunity as maintenance cycles are shortened in-line with increased operating efficiencies.

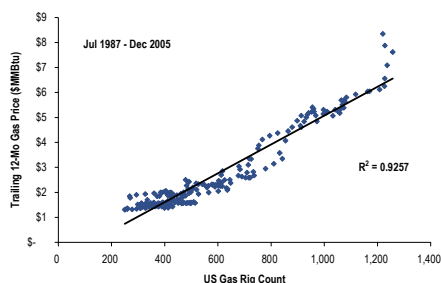
The fluctuations in gas prices are a secondary consideration for companies pondering investment in the emerging shale plays.

The adoption of advanced drilling techniques has other implications worth noting in terms of impact for our coverage companies. For one, the strong historical correlation between gas prices and the U.S rig count has broken down somewhat with the increased prevalence of horizontal drilling.

As illustrated in Figure 27 below, from 1987 through 2005 (a defining year for horizontal drilling) the total U.S. gas rig count exhibited a strong linear relationship ($R^2 = 93\%$) with the trailing twelve-month spot gas price. As a result of this tight correlation, U.S. gas drilling exhibited high degrees of volatility, and rode the “boom and bust” cycles driven by fluctuations in the natural gas price. However, when we make adjustments with the time periods, different patterns emerge. In Figure 28, we see that the relationship between natural gas prices and *total* rig count over the 2004-1H2011 period is a much lower r-squared of 58%. More importantly, Figure 29 shows that there has been almost no correlation ($R^2 = 17\%$) between the U.S. *horizontal* rig count and the trailing twelve-month spot gas price over the past seven-plus years, even though an estimated 80%-plus of these rigs are drilling for gas (with a small percentage drilling oil targets). We attribute this reduced linear relationship between rig count and gas prices to several factors, the first of which is the lower natural gas break-even drilling price for the new horizontal drilling rigs. As we discuss further, the increased power of the new rigs has provided efficiency gains through increased laterals. In addition, unlike traditional natural gas reservoirs, the development of shale reservoirs entail nearly identical wells drilled in terms of depth and length of lateral. There is also little variation in the procedures for completing and hydraulically fracturing the wells. The highly- replicable nature of this process renders shale development much more like an assembly line process, providing substantial opportunities for cost reduction.

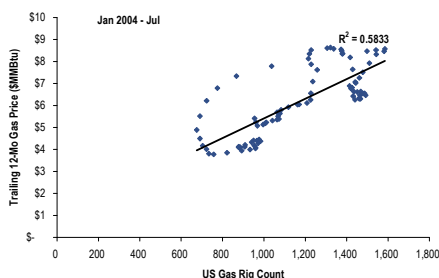
Lastly, we think contractual provisions incorporated in many of the drilling leases (essentially “use-it-or-lose-it”) encourage drilling regardless of the price of gas. According to a survey conducted by CIRA’s E&P analyst Robert Morris, roughly ~40% of natural gas rigs drilling today are doing so to hold acreage. The reduced impact of natural gas price volatility on U.S. horizontal rig counts, should this trend continue, argues that the aftermarket stream associated with these rigs will be both larger and more stable. In addition, increased rig usage will also accelerate eventual replacement demand.

Figure 27. Twelve-Month Trailing Spot Gas Price vs. U.S. Total Gas Rig Count (1967 – 2009)



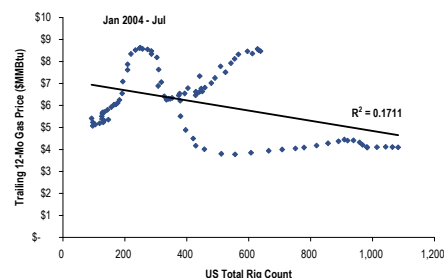
Source: Citi Investment Research and Analysis

Figure 28. Twelve-Month Trailing Spot Gas Price vs. U.S. Total Gas Rig Count (2004 – 2011)



Source: Citi Investment Research and Analysis

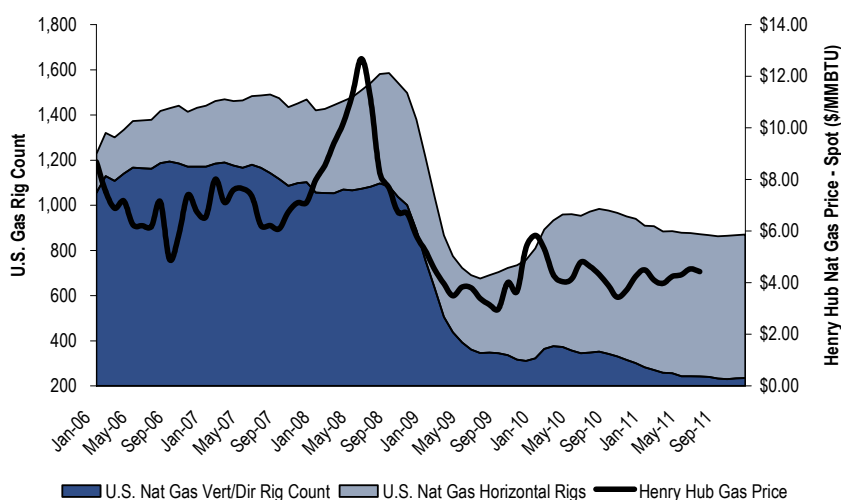
Figure 29. Twelve-Month Trailing Spot Gas Price vs. U.S. Horizontal Gas Rig Count (2004 – 2011)



Source: Citi Investment Research and Analysis

As evident in Figure 30, U.S. horizontal gas rig counts rebounded strongly with low, but improving gas prices while the conventional (vertical) rig count remains near trough levels. Citi's Oilfield Services team thinks that sustained gas prices of \$8-\$10 per MMBtu are required before there would be any material increase in vertical rig counts.

Figure 30. U.S. Gas Rig Count (Horizontal & Vertical / Directional) and Natural Gas Price

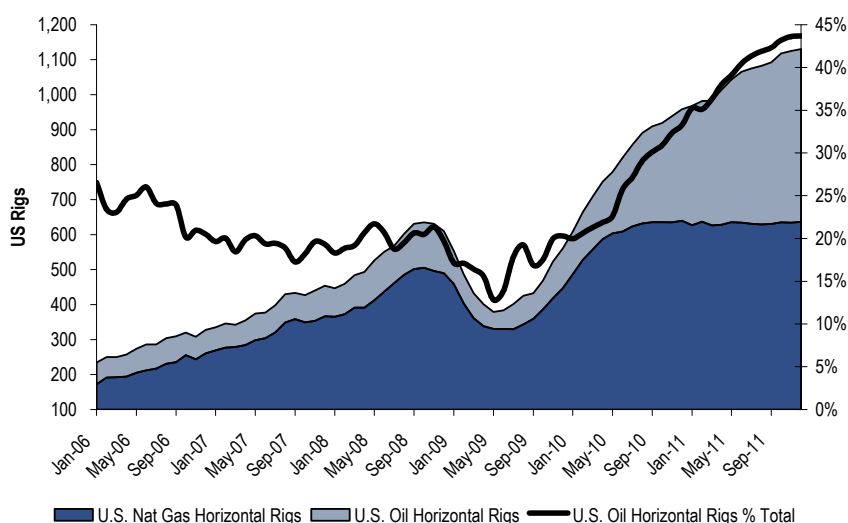


Source: Baker Hughes, EIA, and Citi Investment Research and Analysis

The high price of crude oil relative to natural gas has spurred greater investment in horizontal oil rigs in the US, which tend to have much higher frac stages per well than dry gas wells.

The advancement in drilling technology is impacting more than U.S. natural gas drilling, as these same techniques are now being implemented in the development of onshore shale oil in places like the Bakken Shale, which spreads across wide parts of the Upper Midwest and Canada. Since May 2009, the number of horizontal rigs drilling for oil has increased by ~10x and now comprises roughly 45% of the total U.S. horizontal drilling rig fleet, up from a low of 13% in May 2009. In a sense, there is somewhat of a circular argument here, as improved rig efficiencies and expansion of horizontal gas drilling has created a surplus of capacity, weighing on natural gas prices. Crude oil prices have rebounded sharply from the 2008 lows, and are now roughly four-times more expensive than domestic natural gas (~\$4/MMbtu) prices after normalizing current market prices for heat content. This high price of crude oil compared to natural gas encourages operators to drill for oil in preference to natural gas, and is driving producers to seek liquid rich shale plays to get a more oil-like price for their production. This too has positive implications for the equipment providers, as discussed below.

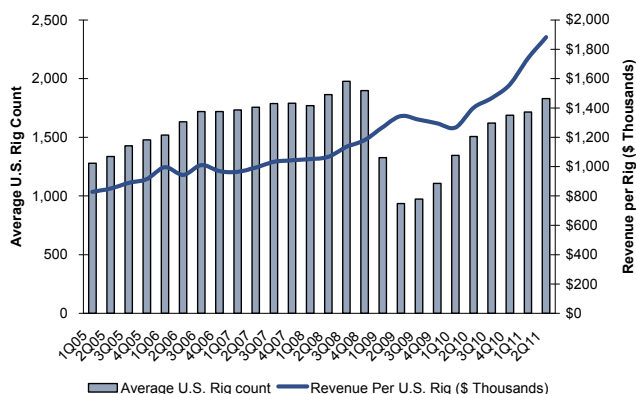
Figure 31. U.S. Horizontal Oil Rigs



Source: Baker Hughes and CIRA Forecasts

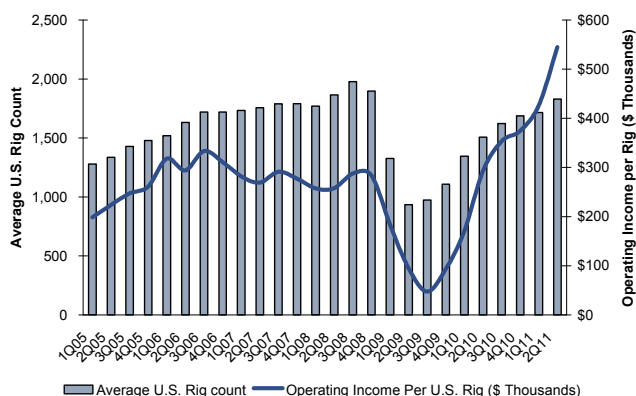
One characteristic of the oily/liquid-rich wells that are being developed is that they tend to have much greater service intensity. This basically refers to the number of frac stages per well – and the trend in the major shale plays is for more stages per well (see Figure 34). Due to this greater service intensity, coupled with higher horsepower requirements, costs of the oily/liquids-rich wells are 40% to 80% higher than those of dry gas wells, per CIRA analyst Robin Shoemaker. The continuous, 24/7 status of operations, and the high intensity nature, also translates in to significant wear and tear on the equipment: industry sources cite the average pump life used in pressure pumping applications has come down from 6-7 years to about 4-5 years today. In short, equipment and parts wear out faster, so durability and quality is more and more coveted, which we see as an additional entry barrier against less sophisticated, “low cost” competitors successfully entering the market. In order to highlight the increase in overall service intensity, below we show the significant growth witnessed in industry benchmark Halliburton’s per-rig (revenue and operating income) metrics.

Figure 32. Halliburton -- North America Revenue per Rig



Source: Company Reports

Figure 33. Halliburton -- North America Operating Income per Rig



Source: Company Reports

The increased lateral length has led to a higher number of frac stages per well and increased overall horsepower required to stimulate the well, both of which we see to be positive factors for equipment providers.

The opportunity created by the advent of advanced drilling techniques extends well beyond providing higher horsepower engines for advanced drilling rigs. Shale development requires hydraulic fracturing stimulation in order to free the trapped hydrocarbons from the shale formation. Hydraulic fracturing is completed by pumping fracturing fluid into the well at tremendous levels of pressure, which is produced by fracturing rig pumps. E&P companies continue to advance horizontal drilling techniques, which have enabled longer laterals. In other words, the horizontal section of the well bore (i.e. lateral) is increasing in length. The increased length of the lateral has led to both a higher number of frac stages needed to develop the reservoir as well as higher overall frac horsepower required to stimulate the well. As illustrated in Figure 34, the-per well increase in fracturing horsepower in certain major shale locations has more than doubled in just two years, with some wells now requiring fracturing horsepower of 45,000.

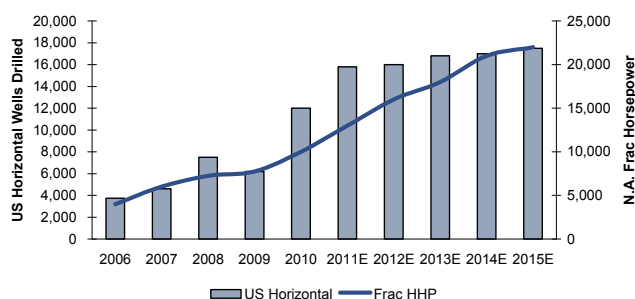
Figure 34. Drilling Service Intensity by Location

		Average HHP	Lateral Length	Number of Stages	Average AFE
Marcellus	2008	6K	3,000 ft	7	\$3.4MM
	2010	30K	5,000 ft	15	\$5.2MM
Bakken	2008	12K	6,500 ft	5	\$3.9MM
	2010	14K	8,500 ft	17	\$6.0MM
Eagle Ford	2008	18K	0 ft	3	\$5.5MM
	2010	36K	6,000 ft	14	\$8.2MM
Permian	2008	12K	3,500 ft	8	\$3.5MM
	2010	30K	4,500 ft	12	\$5.5MM

Source: Halliburton

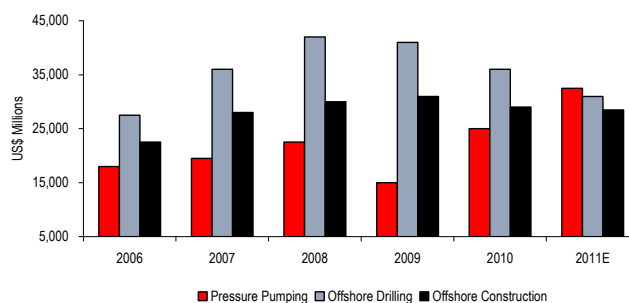
The growth in demand for fracturing services has been greater than that of any other service related to unconventional resource development, with the total hydraulic fracturing market growing from an estimated \$10.8 billion in 2009 to roughly \$16 billion in 2010, based on data from industry consultant Spears and Associates. Manufacturers of the major fracturing rig components (engines, transmissions, pumps, blenders) have struggled to keep up with demand as investment in fracturing rig equipment increased by ~67% in 2010, to \$25 billion and in 2011 is expected to increase by as much as 30%. One example of this is the extended lead times for transmissions cited by a major industry participant, Twin Disc, which were quoted to be roughly 9 months as of its August conference call.

Figure 35. U.S. Fracturing Horsepower



Source: Spears & Associates

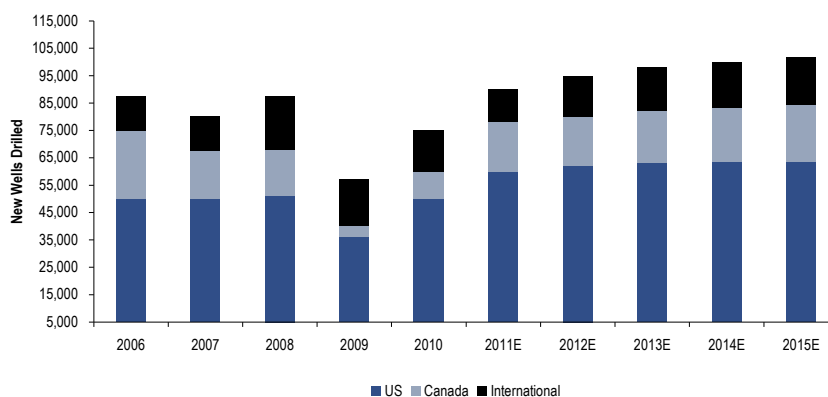
Figure 36. Pressure Pumping Investment



Source: Citi Investment Research and Analysis

One major participant, Weir estimates that ~90,000 new wells will be drilled in 2011, rising to 100,000 new wells in 2015. All of these wells require cementing and the majority will be hydraulically fracture stimulated. Cementing, as well as acidizing and coiled tubing applications require 600 to 1,000 horsepower well service pumps, while hydraulic fracturing requires 2,250 to 3,500 horsepower pumps for delivery of high pressure frac fluids. While we have previously discussed the expected investment in pressure pumping for fracturing, we see the engine OEMs also benefitting from the required investment in engines for these other well servicing applications (cementing, coiled tubing, etc). Coiled tubing rigs alone have been growing at 8% per year and this pace of growth could potentially accelerate with the new coiled tubing applications being developed, particularly drilling.

Figure 37. New Wells Drilled



Source: Spears & Associates

The production and drilling technologies used in the development of unconventional hydrocarbon reservoirs is also now being applied to the redevelopment of conventional fields. These techniques are increasing overall production and allowing for the development of previously unproductive reservoirs. Based on industry estimates, these new techniques could be applied to potentially thousands of older conventional wells with economically attractive results.

Shale Plays...Not Just A US Phenomenon

China launched its first auction of natural gas shale reserves in July; the IEA estimates the country's recoverable gas potential is upwards of 50% larger than the U.S.

While the U.S. is the furthest along in the development of the advanced drilling and production technologies needed to develop nonconventional reservoirs, other countries also possess vast amounts of hydrocarbons trapped in shale, presenting significant potential growth opportunities ahead. China is already beginning to develop its own unconventional gas resources, a key element of its most recent (12th) Five-Year Plan. In late June of this year, China held its first auction of natural gas shale reserves, which could mark an important step for the country as it looks to tap its significant natural gas reserves. In fact, based on IEA estimates, China's 36.1 trillion cubic meters of recoverable reserves is roughly 50% greater than the 24.4 tcm estimated in the US. One of the country's major national oil companies, CNOOC, has invested in North American shale resources partially to accelerate its development of the necessary technological capabilities (horizontal drilling, fracturing, etc) needed to develop in country reserves. In addition to acquiring an oil sands developer in Canada (OPTI), CNOOC has also made two investments in shale gas projects with U.S.-based Chesapeake Energy. Should the country continue to develop the technology and invest in necessary equipment, we see this as a large potential opportunity for U.S.-based engine OEMs like CAT and Cummins

(through its JV partners, as it moves up its horsepower range) to sell to the country's state-owned companies, who thus far have essentially localized everything *but* the engine. CAT is investing \$300MM in the construction of an engine factory located in Tianjin, China estimated to be in production by 2013. The facility will produce CAT 3500 engines which are often used for oilfield power, as well as marine and power gen applications. In addition to China, other emerging regions also hold significant promise. For example, the combined shale gas resources in Argentina and Brazil exceed that of the U.S., and in February, the first horizontal well was drilled in Argentina to begin developing this resource.

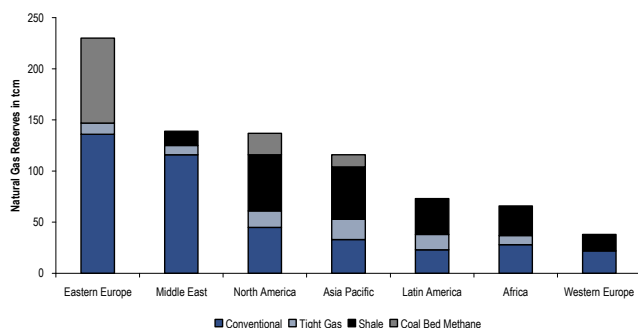
Europe has a significant amount of shale gas reserves, but questions remain on the viability and timing of actual development.

Europe also has significant shale gas resources, technically equal to ~75% of recoverable reserves in the U.S. However the outlook for the development of Europe's resources is mixed. France, which controls ~28% of Europe's shale resources, has outlawed hydraulic fracturing due to environmental concerns. Also, the tax incentives provided in many parts of the U.S. for development of shale gas do not exist in Europe, and the region's service industry is smaller and lacks the expertise in horizontal drilling and fracturing. Poland, which controls close to 30% of Europe's shale gas resources, is currently the most advanced European nation in terms of shale gas development. However, similar to China, Poland will need to invest heavily in higher horsepower directional rigs, fracturing pumps, and other well servicing equipment in order to produce this shale gas. This region (Eastern Europe) could pose an attractive opportunity for engine OEMs and equipment providers down the road.

We see a huge potential revenue opportunity should other regions incorporate shale gas development as part of their energy policy.

Figure 38 below provides a summary of the known global unconventional gas resources by region and type. This chart clearly illustrates the point made above: shale gas is not just a U.S. opportunity. To help to try and quantify the opportunity, in Figure 39 we provide an estimate of the total potential investment required to build the necessary fracturing horsepower required to develop these reserves. This is based on our estimates of the total investment required to build the North American fleet, which is then scaled by each region's known reserves. The point of this exercise is to demonstrate the sizeable revenue opportunity that would be created for prime mover OEMs if any of these regions incorporate shale gas development as a meaningful component of its energy policy. It is important to note that this estimate is only for engine sales, and excludes the more profitable aftermarket service stream created by the short frac engine maintenance cycles.

Figure 38. Global Unconventional Nat. Gas Resources



Source: IEA

Figure 39. Potential Fracturing Pump Engine Sales

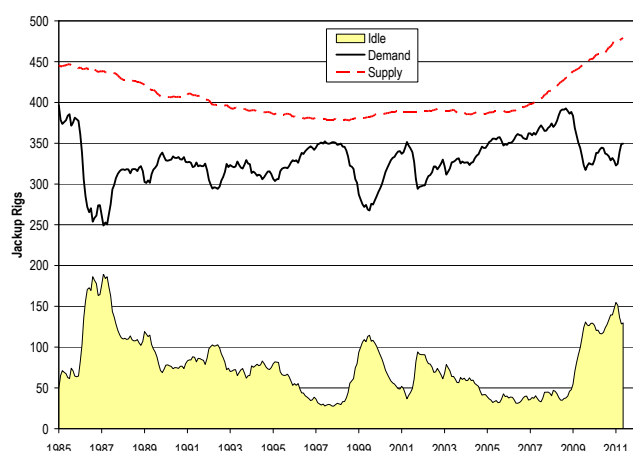
	Unconventional Reserves (TCM)	Engine Sales Potential (US\$BN)	
		Low	High
Eastern Europe	230	\$5.0	\$10.0
Middle East	139	\$3.0	\$6.0
Asia Pacific	116	\$2.0	\$5.0
Latin America	73	\$2.0	\$3.0
Africa	66	\$1.0	\$3.0
Western Europe	38	\$1.0	\$2.0
Total		\$14.0	\$29.0

Source: IEA, Company Reports, Citi Investment Research and Analysis

Offshore – Moving to Deeper Waters

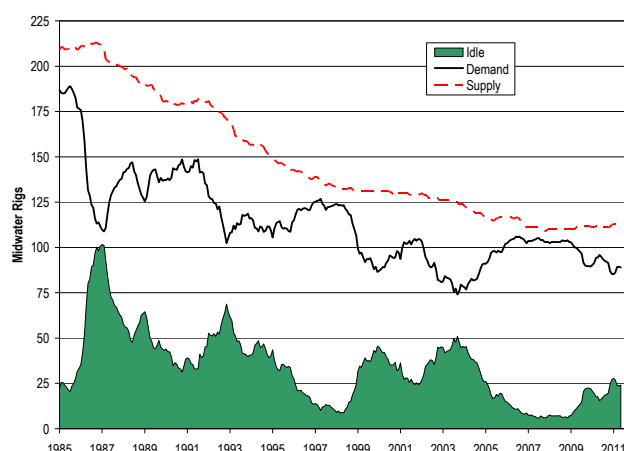
Just as conventional onshore hydrocarbon resources have declined, requiring a transition to more complex and energy-intensive unconventional reservoirs, we have also seen the reduction in easy-to-access shallow water reserves prompt development of new, higher horsepower technologies used to explore the remaining available (yet exceedingly more complex) reservoirs located in deeper water. This is mirrored by diverging demand pattern for offshore rigs, illustrated by the charts below. High demand growth witnessed for deep and ultra deep water rigs and either flat or declining demand for rigs designed for shallower water.

Figure 40. Global Jack-up Rig Demand



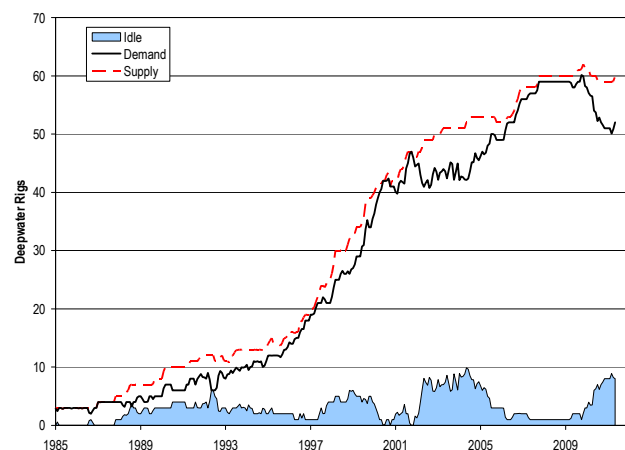
Source: ODS-Petrodata, and Citi Investment Research and Analysis

Figure 41. Global Midwater Rig Demand



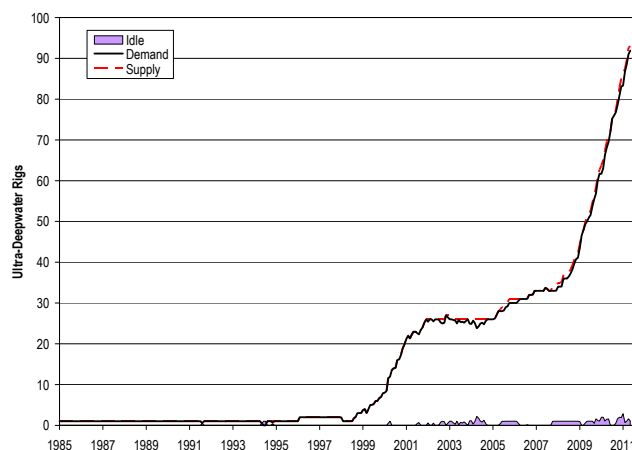
Source: ODS-Petrodata, Citi Investment Research and Analysis
Note: Midwater defined as water depth capability of up to 3,999 feet.

Figure 42. Global Deepwater Rig Demand



Source: ODS-Petrodata, Citi Investment Research and Analysis
Note: Deepwater defined as water depth capability of 4,000 feet to 7,499 feet.

Figure 43. Global Ultra-Deepwater Rig Demand

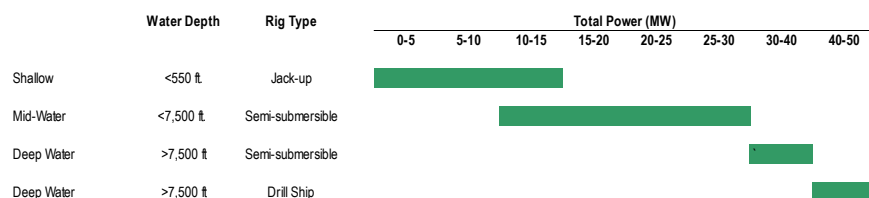


Source: ODS-Petrodata, Citi Investment Research and Analysis
Note: Ultra-Deepwater defined as water depth capability of more than 7,500 feet.

The investment in deepwater exploration is expected to grow by more than 13% annually between 2011 and 2013, reaching an estimated amount of ~\$11 billion in 2013. As illustrated in the following charts, both the power requirements and service intensity increase alongside increases in operating and drill depth. Halliburton expects the average deepwater drill depth to increase by ~5,000 feet over the next three years, which is an increase in length of 20% to 25%. Also, the

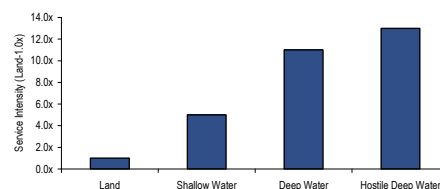
offshore locations are becoming more hostile, and both temperature and pressure become more challenging issues as depth increases.

Figure 44. Offshore Rig Power Requirements by Operating Depth



Source: Citi Investment Research and Analysis

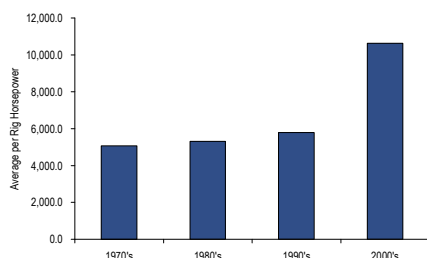
Figure 45. Service Intensity



Source: Citi Investment Research and Analysis

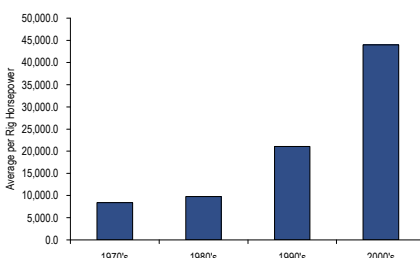
While average power requirements have been increasing over time, the last decade experienced a significant increase in average rig horsepower across rig types as offshore drilling operations are focusing on developing deeper and more complex hydrocarbons reservoirs, both of which require higher power per rig. We highlight three visible examples below.

Figure 46. Jack-up Average Horsepower per Rig



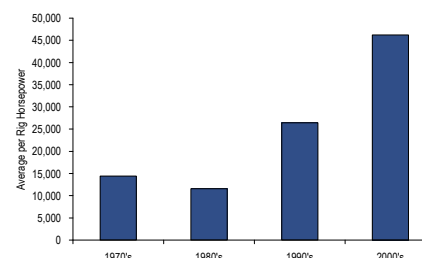
Source: RigBase

Figure 47. Semi-submersible Average Horsepower per Rig



Source: RigBase

Figure 48. Drill Ship Average Horsepower per Rig



Source: RigBase

In addition to the ongoing efforts to explore deeper and more complex offshore hydrocarbon reservoirs, resulting in demand growth for higher horsepower engines, the expansion of offshore exploration beyond the “golden triangle” is also driving demand. Historically, offshore exploration was concentrated in three regions: The Gulf of Mexico, South America, and West Africa. However, offshore E&P activities are now expanding to include Australia, Southeast Asia, and the Mediterranean.

The increasing horsepower requirements of the offshore drilling industry should translate into an attractive revenue opportunity for engine OEMs. Based on the current new build pipeline for offshore rigs, we estimate the cumulative engine sales opportunity for OEMs could be more than \$3.5 billion through 2014. These engine sales also provide a very attractive stream of parts of service revenue to the OEMs driven by the high cost of rig downtime and failure. But clearly the opportunity set is not limited to the engine makers. For example, while only about 15% of Eaton’s Hydraulics sales go to the Energy market vertical, the company (which is a global leader in clutches and brakes used in both offshore and land drilling applications) has highlighted this business as one of its faster-growth markets, estimated to grow at a ~8% CAGR over the next several years.

Figure 49. Estimated Offshore Power Solutions Investment

(\$millions)

	2011	2012	2013	2014
Rigs Under Construction				
Jack-up	13	23	34	9
Semi-Submersible	10	7	5	3
Drill Ship	11	8	25	4
Total	34	38	64	16
Est. Engine Investment				
Jack-up	\$234	\$414	\$612	\$162
Semi-Submersible	\$320	\$224	\$160	\$96
Drill Ship	\$330	\$240	\$750	\$120
Total	\$884	\$878	\$1,522	\$378

Source: Company Reports and CIRA Estimates

However, like onshore unconventional reservoirs, the opportunity created by the offshore industry focusing on developing increasingly complex hydrocarbon reservoirs is more than just a drilling story. As offshore exploration moves in to deeper waters, it is no longer feasible to use pipelines connected to offshore platforms as the primary means of production. Instead, there is a growing use of Floating Production Storage and Offloading vessels (FPSOs). These vessels require massive amounts of horsepower for propulsion, processing (water separation, gas treatment, oil processing, and water injection), and compression for both gas reinjection for well stimulation as well as for gas lift. As evident by the \$160 million Petrobras contract awarded to GE to supply both power generation and compression for two FPSOs, each vessel provides diesel engine, gas turbine and compressor OEMs with a revenue opportunity approaching \$100 million. Between now and 2015, Petrobras alone is expected to build up to 20 FPSOs, which using the GE contract as a simple example, represents a \$1.5 billion-plus potential opportunity for turbine and compressor manufacturers. With offshore exploration expanding beyond the golden triangle, we think this will drive higher needs for these production units.

Older rigs, which are limited to shallow water and often equipped with dated technology, provide another potential revenue opportunity as the decommissioning of these rigs is often completed with the assistance of heavy lift vessels. In the North Sea, there are currently 260 platforms (2.4 million tons of steel) that need to be decommissioned, with the total cost of this process estimated to be ~\$30 billion. In addition to the North Sea, the Gulf of Mexico has another 650 platforms that need to be removed. These decommissioning activities are set to spike shortly after 2015.

Figure 50. Heavy Lift Vessel



Source: Marine Insight

Significant Infrastructure Investment Required

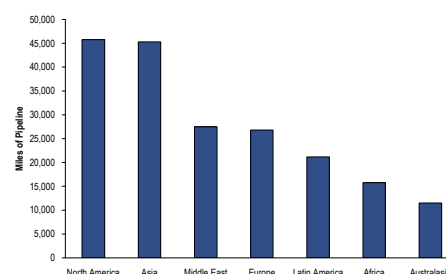
Further growth in oil and gas production also presents attractive midstream and downstream opportunities for our coverage companies through the need for additional infrastructure investment required for the transportation of the hydrocarbons from the well to the end user. Both the development of shale gas and the growth of natural gas fired power generation will drive demand for additional investment in natural gas pipeline infrastructure, including new compressor stations. As we highlighted earlier, the low price of natural gas in the U.S. relative to crude oil is causing producers to seek liquid rich shale plays to get a more oil-like price for their production. This is stimulating need for more natural gas processing and NGL transportation. The following charts highlight the potential magnitude of this investment, both in North America as well as globally.

Figure 51. North America Natural Gas Infrastructure Spending Forecast (2011E to 2013E)

US\$ in billions	Storage	Processing Plants	Lateral Pipe	Gathering Pipe	Mainline Pipe & Compression	Total
Central (incl. Rockies)	\$0.9	\$4.0	\$2.5	\$8.5	\$23.2	\$39.1
Midwest	0.2	0.2	2.7	0.5	6.1	9.7
northeast	0.7	5.9	7.3	5.9	12.8	32.6
Southeast	1.1	0.0	7.6	0.4	26.5	35.6
Offshore	0.0	0.7	0.1	0.2	4.3	5.3
Southwest	1.4	6.9	5.4	13.7	19.0	46.4
Western	0.3	0.1	1.7	0.8	6.0	8.9
Arctic	0.0	0.2	0.0	0.1	0.0	0.3
Canada	0.2	4.1	2.3	11.5	8.9	27.0
Total	\$4.8	\$22.1	\$29.6	\$41.6	\$106.8	\$204.9

Source: Citi Investment Research and Analysis

Figure 52. Global Future Pipeline Projects



Source: Simdex

The Interstate Natural Gas Association of America ("INGAA") has developed a longer term forecast for the investment needed for the incremental gas infrastructure, which is summarized below. Based on their forecast, through 2020 the average annual investment in compression just for U.S. pipeline transmission will be ~\$560MM. Clearly, this opportunity expands beyond the U.S., and countries such as Russia, Indonesia and China are driving the market for energy infrastructure. To highlight a recent example in Asia, we highlight CAT's shipments (from its Lafayette, IN facility) of gen-sets for the Asian Gas Pipeline project. This the largest current pipeline construction project in the region, which will transport gas from Kazakhstan to China, and ultimately meet roughly 2% of China's energy consumption when it comes on-line in late 2013. CAT is delivering gen-sets to provide both prime power for the gas compression stations, as well as emergency backup power.

Figure 53. Incremental Gas Infrastructure

Summary of Incremental Gas Infrastructure Added in the Reference Case (cumulative)	2011 to 2020	2011 to 2035	Average Annual
Inter-regional Pipeline Capacity (Bcfd)	29	43	1.7
Miles of Transmission Mainline (1000s)	16.4	35.6	1.4
Miles of Laterals to/from Power Plants, Storage Fields and Processing Plants (1000s)	6.6	13.9	0.6
Miles of Gathering Line (1000s)	165	414	16.5
Inch-Miles of Transmission Mainline (1000s)	491	1,043	42
Inch-Miles of Laterals to/from Power Plants, Storage Fields and Processing Plants (1000s)	142	304	12
Inch-Miles of Gathering Line (1000s)	592	1,518	61
Compression for Pipelines (1000 HP)	3,039	4,946	197
Gas Storage (Bcf Working Gas)	NA	589	24
Processing Capacity (Bcfd)	18.1	32.5	1.3

Source: INGAA Foundation

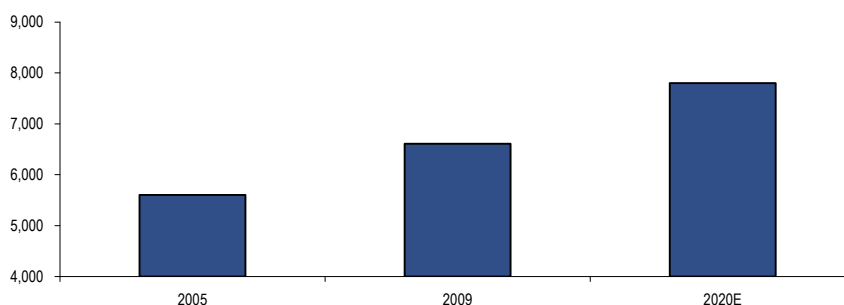
Figure 54. Natural Gas Infrastructure Spending Forecast

Natural Gas Infrastructure Capital Requirements (Billions of 2010\$)	2011 to 2020	2011 to 2035	Average Annual Expenditures
Gas Transmission Mainline	\$46.2	\$97.7	\$3.9
Laterals to/from Power Plants, Gas Storage and Processing Plants	\$14.0	\$29.8	\$1.2
Gathering Line	\$16.3	\$41.7	\$1.7
Gas Pipeline Compression	\$5.6	\$9.1	\$0.3
Gas Storage Fields	\$3.6	\$4.8	\$0.2
Gas Processing Capacity	\$12.4	\$22.1	\$0.9
Total Gas Capital Requirements	\$98.1	\$205.2	\$8.2

Source: INGAA Foundation

Another factor increasing the need for pipeline infrastructure (and compression) is the increase in average distance travelled - the result of the longer spreads between natural resources and points-of-use. This is partially driven by the increasing use of LNG imports among Asian countries. China alone currently has six large liquefied natural gas terminals under construction, and is expected to double its LNG imports by 2015. Following the Fukushima accident, Japan is also expected to be a larger importer of LNG. But pipeline infrastructure is obviously not just built in importing countries -- exporting countries also need additional pipeline infrastructure, all of which will require investment in processing and compressing capabilities.

Figure 55. Average Miles Traveled per Bcm of LNG



Source: Citi Investment Research and Analysis

CAT has a long history selling to the pipeline industry, where it serves customers from three separate entities.

Getting crude oil to market via rail is becoming more relevant in places like the Bakken Shale in North Dakota.

Particularly for Caterpillar, the rampant growth in shale plays and related infrastructure development provides more than just the potential to capture upside from increased sales in to “Oil and Gas” markets. The company has had major involvement in the North American pipeline industry for over 50 years, and serves its global customers using a three-pronged approach. Specifically, its Global Pipeline Division manufactures and distributes equipment often associated with construction markets, such as hydraulic excavators and motor graders (as well as pipelayers), which get used in the maintenance and construction of pipelines. CAT’s Global Petroleum Division provides large engines for compressors used to transport petroleum products through the pipeline. Its path to reaching pipeline contractors and large public firms like El Paso and Kinder Morgan is through its global dealer Pipe Line Machinery International, which is the lone CAT dealer that does not adhere to regional boundaries and only serves one industry (pipelines) globally.

In cases where infrastructure constraints or distances preclude pipeline construction, we have seen rail mentioned as an increasingly viable candidate to transport oil. This has also accelerated in certain regions where weight-load restrictions are hindering truck’s role in getting crude oil to market. Rangeland Energy LLC, for example, is building a greenfield storage hub and railroad facility to take oil away from the Bakken Shale and move it to other markets where values are higher. Partly as result of infrastructure constraints in this region, producers have been forced to sell their crude oil at as much of a \$20/bbl discount to the price of West Texas Intermediate (WTI). Some independent oil and gas companies, including EOG Resources, are actually building rail facilities. With CAT’s growing presence in rail markets globally, the result of its acquisitions of Progress Rail and more recently EMD, this is another example of the tangential benefits it may realize from development of trends in global energy markets.

Figure 56. Illustration of Pipeline Construction



Source: Citi Investment Research and Analysis

Overview of Major Engine Producers

Caterpillar Oil & Gas

Mention of Caterpillar instinctively triggers many investors' thoughts to big yellow CAT-branded iron on a commercial jobsite or highway project, but our sense is that some are less aware of the company's dominant position as a supplier to global energy equipment markets. CAT has a long history (over 80 years) serving the global oil and gas industry, which was enhanced by its acquisition in the early 1980's of Solar Turbines, which it purchased from International Harvester. Solar's history dates all the way back to the 1920's, when it began as an aircraft manufacturing company, before developing in to a gas turbine technology company in the 1940's.

CAT's yet-to-close acquisition of MWM will provide it with flexible fuel technologies, which are becoming more important globally.

Caterpillar sells power solutions to the oil and gas industry through two of its formerly-defined (until 2011) business groups, which are now collapsed in to the Power Systems segment for external reporting purposes. The Marine and Petroleum segment provides reciprocating engines for a wide number of applications in the oil and gas industry including powering both onshore and offshore drilling applications, well service rigs, and to power reciprocating compressors. The Marine segment captures a wide range of end-markets (from large engines sold under the MaK brand providing auxiliary power for tanker ships to yacht engines), but because a reasonably large part of it is focused on work boats that shuttle back and forth to offshore rigs, it is grouped with the non-turbine piece of Oil & Gas. These engines are capable of burning a wide selection of fuels and range in horsepower from approximately 100 to 10,000 (8,000 for gas engines). As mentioned earlier, the announced, but not closed, acquisition of German-based MWM will also add flexible fuel technologies to the company's product offerings. Oil and gas customers are increasingly demanding that the engines they acquire be capable of burning multiple types of fuel such as diesel and dirty (unprocessed) gas with no adjustment needed.

The Marine and Petroleum segment also offers well service transmissions ranging from 350 to 3,000 hp for use with well service vehicles, and fracturing and workover rigs. Historically, additional fabrication was required when combining a CAT engine with a transmission manufactured by another OEM. With the introduction of Caterpillar transmissions, this problem is eliminated making the rig construction process that much easier. This also increases that percentage of rig content acquired from one OEM, which reduces the number of aftermarket service providers and should accrue to CAT's benefit.

Exports have typically accounted for over two-thirds of Solar's sales.

Through Caterpillar's wholly owned subsidiary, Solar Turbines, the company offers gas turbines ranging from 1 to 22MW (30,000 horsepower) that can be used as mechanical drives for natural gas compression, production, or marine propulsion, as well as for power generation. We estimate that roughly 80% is sold in to Oil & Gas markets, with the balance going to Power generation, namely in instances where co-generation can be used. Speaking to the global nature of the oil and gas market, Solar is heavily export-dependent (it is one of the 50 largest exporters in the U.S.), with exports accounting for over two-thirds of sales from the U.S. (where about 85% of its physical assets are based).

Figure 57. Caterpillar Oil & Gas Reciprocating Engines and Turbines

Reciprocating Engine	Power Range
Drilling	440 - 10,880 bhp
Well Service	230 - 2,250 bhp
Well Service - Hazardous Location	205 - 1,110 bhp
Gas Compression	95 - 8,180 bhp
Production Engines	215 - 21,760 bhp
Fire Pumps	292 - 1985 bhp
Gas Turbines	
Mechanical Drive	7,700 - 30,000 bhp
Generator Sets	5.7 - 21.7 MW

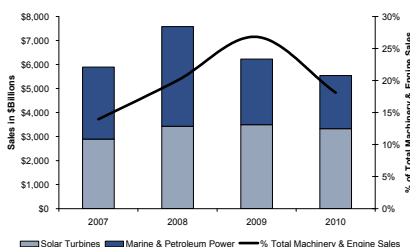
Source: Company Reports

Note: 1 MW equals ~ 1,341 bhp

The company's high margins and return on assets help speak to the attractiveness of CAT's Oil and Gas franchise.

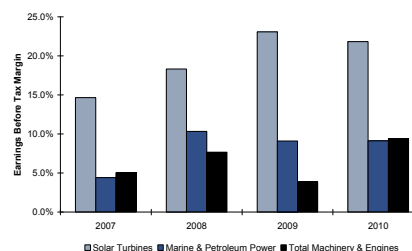
While end-market break-downs in terms of dealer sales have been provided for many years, the company only provided a more granular look at actual CAT sales in to Marine & Petroleum Power and Turbine markets for the past few years. Over this period, total sales have ranged between ~\$5.5 to \$7.5 billion, or about 15% to 25% of total Machinery and Engine sales. Admittedly this timeframe does span a relatively strong period in global energy markets, minus of course the collapse in oil prices starting in mid/late 2008, but with long-lead times and a strong backlog position, Solar sales were actually up in 2009 versus 2008. More importantly, when we look at profitability and returns, these segments have demonstrated attractive characteristics. This is especially true for Solar, with margins over this period more than twice that of the broader company average. We think the company's high profit margins are a function of several factors, most notably its strong market share position (discussed in greater detail below). We believe Solar offers somewhat differentiated technology, which helps to drive attractive energy efficiency characteristics across its power range, which is a key advantage given that fuel costs tend to be the #1 operating expense. Further, the Solar Turbine business also has an attractive aftermarket service business which contributes between 40% and 50% of total revenue each year, enhanced by a huge global installed base of close to 14,000 turbines.

Figure 58. CAT Oil & Gas Sales



Source: Company Reports

Figure 59. CAT Oil & Gas Profit

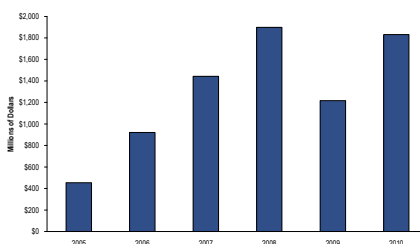


Source: Company Reports. Note: segment profit excludes corporate expense, but includes an allocated portion of the service cost component of post-retirement benefit costs.

A high level of profitability, combined with Solar's modest invested capital requirements results in returns well in excess of those produced by the broader company. The segment's capital intensity is low due to a combination of its modest required capex needs (average capex ~2.5% of sales) and the customer advances Solar receives from customers during the turbine manufacturing process. At the time customers place new orders for Solar turbines they are required to give Solar a

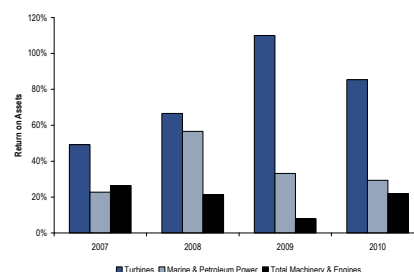
down payment equal to an agreed upon percentage of the total customer purchase price. Additional advances are required each month during the manufacturing process with the residual balance due at the time of delivery. This payment arrangement effectively provides Solar with an interest free loan and significantly reduces the segment's capital reinvestment requirements.

Figure 60. CAT Customer Advances



Source: Company Reports
Note: Customer advances received for turbines (largest piece), MaK engines, mining trucks, and locomotives.

Figure 61. Caterpillar Segment Return on Assets



Source: Company Reports
Note: ROA defines as earnings before taxes / total assets.

Cummins' aggressive, targeted approach to grow its presence in Oil and Gas markets have been very successful, and we see a continuation of this push going forward.

Cummins enjoys a market-leading position in North America of engines used in pressure pumping applications.

Cummins Oil & Gas

Cummins manufactures diesel and natural gas engines (~50 to 3,000 hp) used for a wide range of applications in the oil and gas industry including power solutions for onshore and offshore rigs, gas compression, and well servicing. While it made two initial attempts to enter the market in the past, Cummins does not manufacture turbines. It is a relatively late entrant into the O&G market, potentially deterred by the stringent costs and hurdles required to meet safety regulations, and the company's current limitations in horsepower ranges and fuel types have precluded it from competing effectively in markets like off-shore drilling and a wider segment of the compression market. That said, it has targeted this sector for growth, and made several major investments to back this up. Most recently, the company announced the opening of two "Centers of Excellence" to expand its offering from simply being a drop-in engine manufacturer to a provider of complete solutions that include customized, integrated power packages. The onshore Center of Excellence is located in Houston, Texas and offers products including packages for workover rigs, pump drives, and power modules for onshore rigs, while the offshore Center for Excellence is located in Singapore (in close proximity to a high concentration of shipyards and oil platform builders) and offers power modules for offshore rigs, offshore emergency power gensets, and fire power pump drivers.

Cummins enjoys a market leading position in North America in the manufacturing of engines used to power hydraulic fracturing units with an estimated market share between 50% and 60%, followed by Detroit Diesel and CAT. This market remains red hot, and we have heard of lead times extending out to as far as nine months. Cummins also provides power solutions for drilling, but trails both Caterpillar and Detroit Diesel in the onshore market and has a limited presence in the offshore market. The company's late entrance into the market partially explains its competitive position in the drilling markets as the company's competitors have served the market for decades and have a large installed base, which when combined with reasonably high switching costs, has limited Cummins' penetration. The company's offshore positioning is also a function of its lack of larger engines which limits Cummins' addressable market to shallow water jack-ups and semi-submersibles, along with emergency and fire pump engines. Cummins faces similar challenges as a power solution provider for the compression market. The company's largest engine is 850 horsepower which limits Cummins to only 13% of

Investment at its Seymour, IN facility coupled with the launch of transmissions for fracturing applications will help Cummins address a wider section of O&G markets.

the addressable compressor engine market and prevents the company from selling into the most profitable market segment, which is for engines larger than 1,000 hp.

That being said, Cummins is introducing higher horsepower engines to expand its addressable market in both drilling and compression. This will be aided significantly by its capacity expansion at the company's Seymour, Indiana facility, which will add engine capacity above the high end of its current product range (91 liters). In addition to providing power solutions, Cummins is partnering with Pacific Rim Engineered Products of Canada to develop a 2,500 hp transmission for the pressure pumping market, scheduled to be introduced in the middle of 2012. By introducing a transmission, Cummins aims to offer a more seamless solution for its customers who will be able to avoid the fabrication currently needed to match-up engines and transmission produced by different OEMs. The transmission will also increase the amount of content acquired from one OEM which allows for a more fluid aftermarket service experience.

Figure 62. Cummins Oil & Gas Engines

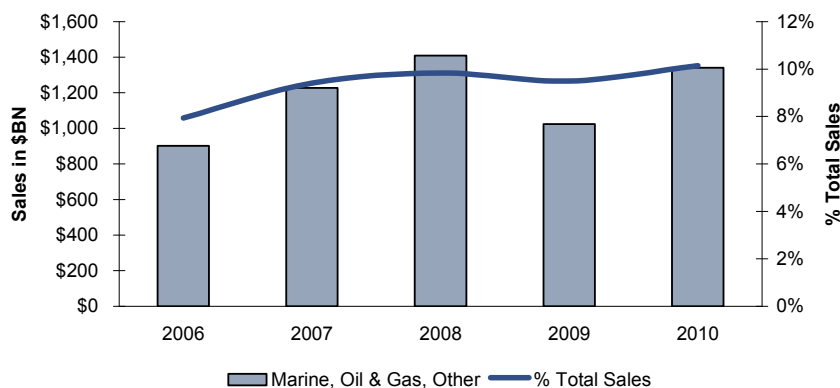
Engine	Power Range
Mechanical Drilling Engines	320 - 3,000 bhp
Land-Based Oilfield Generator Sets	454 - 815 bhp
Land-Based Drilling Power Modules	770 - 1,480 bhp
Offshore Emergency Generator Sets	74 - 152 kW
Offshore Drilling Power Modules	1,855 - 2,547 bhp
Gas Compression Engines	41 - 850 bhp
Well Servicing Engines	
Off-Highway	85 - 3,000 bhp
On-Highway	345 - 600 bhp
Hazardous Areas	365 - 500 bhp

Source: Company Reports

Note: 1 kW = ~1.341 bhp

We use Cummins' Mining, Marine, Rail, Oil & Gas, Government component of Engine segment sales as a proxy for the company's total sales to the oil and gas industry. We think the oil and gas generated aftermarket revenue, which is captured in the distribution segment, will reasonably offset the engine sales to markets other than oil and gas that are included in this number (namely Mining) and provide a reasonably accurate depiction of its true exposure.

Figure 63. CMI Estimated Oil & Gas Sales



Source: Company Reports

Competitive Positioning

Market shares vary across regions and application.

We find CAT to be the global leader of power solutions for the onshore drilling market in North America.

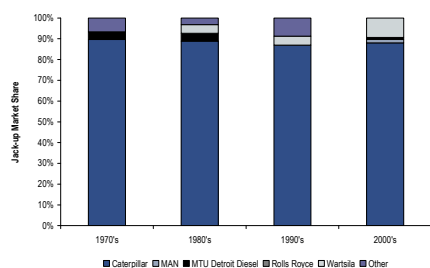
The oil and gas industry requires power solutions for numerous applications during the hydrocarbon production cycle. The power solutions market for each of these applications, such as onshore drilling, or compression, is characterized by its own unique competitive landscape with no OEM serving as the market leader across all markets. Of course, these markets are global in nature, so regional dynamics also come in to play, but we tend to see the same general roster of names across most markets and geographies. Below we highlight our assessment of the competitive landscape across the key product focus.

Based on conversations with industry participants and other data points, we think Caterpillar is the leading provider of power solutions for the onshore drilling market, followed by MTU Detroit Diesel and then dropping-off to include producers like Cummins. Caterpillar has been producing engines for the oil and gas industry for over 50 years and the company's large installed base provides them with an advantage in securing engine orders for new rigs due to ease of aftermarket service.

Cummins is the leading North American manufacturer of engines to power hydraulic fracturing pumps, followed by Rolls Royce and Daimler's jointly owned Detroit Diesel, and Caterpillar. Looking at another key component of frac units – transmissions – we find Allison Transmission and Twin Disc to be the leading producers today. However, due in part to its recent investment in higher horsepower transmission capacity (increasingly prevalent as unconventional drilling entails higher service intensity), we believe CAT has gained share in the market. Also, as mentioned earlier, Cummins is scheduled to enter the market in 2012. When engines and transmissions are manufactured by different OEMs, some fabrication is required for the pieces to work together. By offering both engines and compatible transmissions, Caterpillar and Cummins will be able to offer products that can simply be dropped into the frac rig without the need for fabrication and they are hoping this convenience of use will allow them to increase penetration. The increased focus on developing both unconventional oil and gas shale reserves has driven significant investment in hydraulic fracturing pumps in recent years, and the outlook remains favorable.

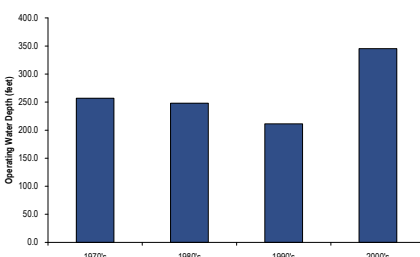
Looking at off-shore markets, Caterpillar has a near monopoly position in providing engines (term engines used to represent both reciprocating engines and gas turbines used for power solutions in offshore drilling rigs) for the Jack-up market and has maintained this market leadership for several decades. During the past several years, European-based Wartsilla has also significantly increased its share of the market, though this came at the expense of industry participants other than Caterpillar. The last decade also saw a meaningful increase in the average operating depth for Jack-ups as well as a large increase in the average horsepower per rig. The increase in both operating depth and per-rig horsepower is logical because power requirements increase with drilling depth.

Figure 64. Jack-up Market Share by Delivery Year



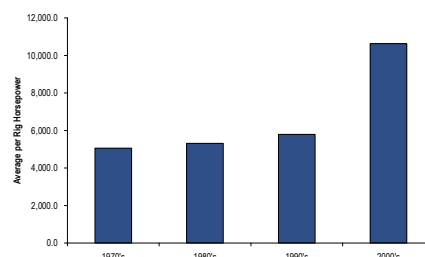
Source: RigBase

Figure 65. Jack-up Average Operating Depth



Source: RigBase

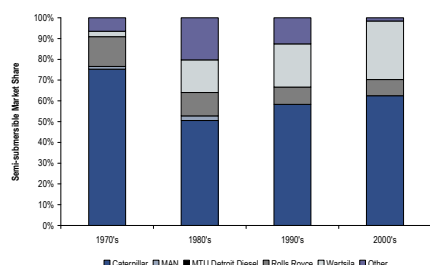
Figure 66. Jack-up Average Horsepower per Rig



Source: RigBase

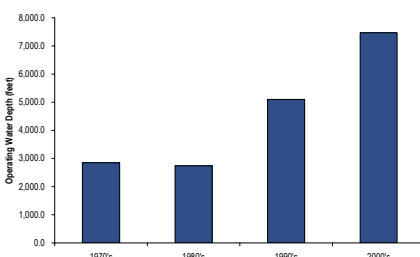
Caterpillar is also the leading provider of engines for Semi-submersibles, though Wartsilla also has a meaningful share of the market. Similar to Jack-ups, both the average operating depth and power requirements for semi-submersibles has been increasing, as depicted in Figure 68 and Figure 69.

Figure 67. Semi-submersible Market Share by Delivery Year



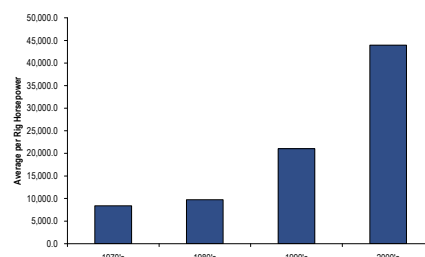
Source: RigBase

Figure 68. Semi-submersible Average Operating Depth



Source: RigBase

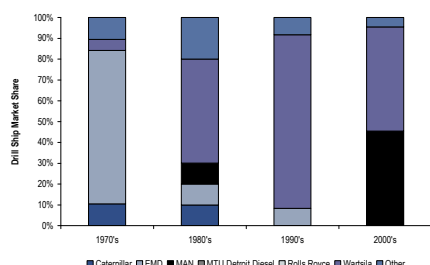
Figure 69. Semi-submersible Average Horsepower per Rig



Source: RigBase

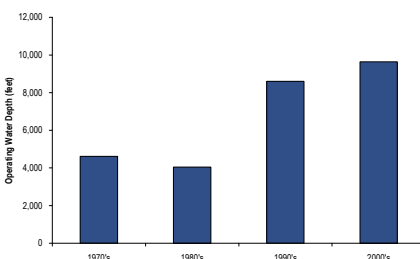
EMD, which is now owned by Caterpillar, was the leading provider of engines for drill ships in the 1970s under its ownership by General Motors, but the company quickly ceded share to Wartsilla and MAN Diesel (through Korean licensees) who are now the dominant players in this market. In 2010, Caterpillar introduced MaK engines for the marine industry which are large enough to be used on drill ships but the majority of engine awards for drill ships under contract still go to Wartsilla or MAN Diesel.

Figure 70. Drill Ship Market Share by Delivery Year



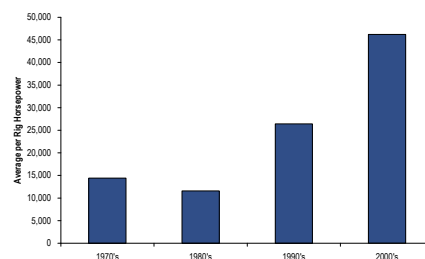
Source: RigBase

Figure 71. Drill Ship Average Operating Depth



Source: RigBase

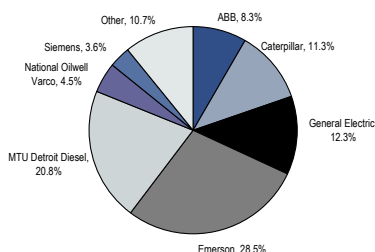
Figure 72. Drill Ship Average Horsepower per Rig



Source: RigBase

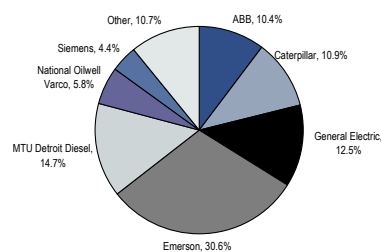
In addition to manufacturing the engine (prime mover), Caterpillar also produces electric generators for offshore rigs, but the company's market share is much smaller than its engine share. Electric generators are combined with the prime mover to form the engine-generator or "genset." The role of the generator is to convert mechanical energy into electrical energy. Emerson is the leading producer of generators for offshore rigs. Other significant market participants include MTU Detroit Diesel, GE, Caterpillar and ABB. Unlike competitive positioning in the offshore prime mover market, which varies across rig class (water depth), competitive positioning in the offshore generator market is fairly stable across rig types (see Figure 73. and Figure 74), except for Detroit Diesel, whose generators have a greater presence in shallow water rigs.

Figure 73. Offshore Generator Market Share by Rig Count



Source: Company Reports

Figure 74. Offshore Generator Market Share by Installed Base



Source: Company Reports

Through its wholly owned subsidiary, Solar Turbines, Caterpillar enjoys a market-leading position in gas turbines. Based on the midpoint of our market share analysis, we estimate that Solar's share of the gas turbine market in its power range (1.2 to 22MW) is ~70%, but note that our range of estimates for Solar's market share is fairly wide. We have determined this range of estimates by combining the company's disclosure of its annual gas turbine production (including the percentage sold to the oil and gas market), with published industry production data (note that published data excludes output from Solar). Solar's turbines are the industry leader in energy efficiency in their power range, which provides Solar with a meaningful advantage by reducing its customer's total cost of ownership. Considering the fact that fuel costs can be up to 80% of total operating expenses these savings may be substantial.

Figure 75. Estimated Solar Gas Turbine Market Share

Output Range (MW)		Units Ordered (Ex. Solar Mechanical Drive Gas Turbines)			
Low	High	2007	2008	2009	2010
1.00	2.00	3	2	1	3
2.01	3.50	2	0	0	6
3.51	5.00	2	1	0	0
5.01	7.50	12	0	0	0
7.51	10.00	18	2	0	0
10.01	15.00	34	18	5	1
15.01	20.00	26	17	16	34
20.01	30.00	132	54	51	56

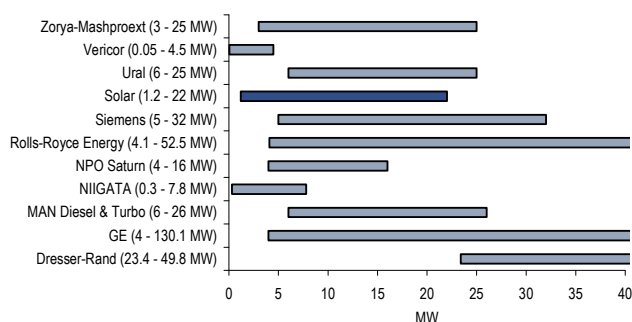
Implied Market Share:					
Low:		45%	63%	67%	62%
High:		71%	86%	92%	85%

Source: Diesel and Gas Turbine Worldwide and CIRA Estimates

Solar's main competitors consist of GE, Siemens and Rolls Royce. However, it is important to note that Solar (and turbines in general) face competition from other equipment technologies that can be used in many of the same applications. One of which (electric motors) is gaining acceptance, especially in the US market. This is partly driven by increasingly stringent emission regulations, which play in to the hands of electric drives given their superior energy efficiency. This is compounded as more oil and gas deposits are being found in less isolated, more urban areas, which not only are more likely to have greater grid access, but also interested in keeping noise "emissions" as low as possible. Furthermore, another trend in offshore production that may impact Solar's competitive position is the move toward power ranges outside of Solar's range. For example, the GE turbine's ordered to power Petrobras' FPSOs were each ~31.1 MW, and this trend will likely continue as offshore exploration moves into deeper waters.

Caterpillar is also a leading provider of natural gas engines for land production (gas transmission pipelines). GE (Waukesha), Cummins and Rolls Royce also compete in this market.

Figure 76. Gas Turbine Mechanical Drive



Source: Diesel & Gas Turbine

Figure 77. Gas Compressor and Drive OEMs

	Mechanical Drive Gas Turbine	Mechanical Drive Steam Turbine	Centrifugal Compressor	Natural Gas Engine
Caterpillar (Solar)	X		X	X
Cummins				X
Arrow Engine Company - Trimans Corp				
Dresser Rand	X	X	X	
Elliott Company	X	X	X	
GE Oil & Gas	X	X	X	X
Howden Processor Company			X	
MAN Turbo	X	X	X	
Rolls Royce	X		X	X
Samsung Techwin			X	
Siemens AG	X	X	X	
Wartsilla				X

Source: Compressor Technology Sourcing Supplement

Engines, Turbines, and Transmissions

Reciprocating engines, such as internal combustion engines found in automobiles, use pressure to create linear motion in pistons (backwards and forwards inside a cylinder) which is transformed into rotational motion (energy) in the crankshaft.

Similar to reciprocating engines, turbines also produce rotational motion, but instead of converting linear motion generated from a piston, turbines convert fluid motion from gases or liquids into rotational energy by running the fluid over blades. An example of a Solar turbine is provided below. The compressor takes in outside air and pressurizes it, and this pressurized air is then passed to the combustor where fuel is added and the mix is ignited. The heated molecules expand and move at a high velocity to the turbine section where the energy is converted into rotational power.

Reciprocating engines require a lower initial investment, have greater fuel flexibility, and are more efficient with fluctuating loads while turbines have a superior power to weight ratio, and lower downtime.

Reciprocating engines and turbines have comparative strengths and weaknesses that make each one the superior prime mover for certain applications. Compared to turbines, reciprocating gas engines offer a greater degree of fuel flexibility with dual fuel engines able to operate using fossil fuels, biofuels, or natural gas. The higher degree of engine standardization results in a much lower required initial investment compared to turbines. Reciprocating engines also offer superior fuel efficiency in operations requiring fluctuating loads.

Gas turbine engines offer a greater power-to-weight ratio than a conventional reciprocating engine and also have a smaller total installed base so they are a superior prime mover in applications with limited space. Turbines produce low levels of NO_x and CO that are compliant with the most stringent levels of current emissions regulation and achieve this result without the need for after-treatments such as SCR. While reciprocating engines do have a much lower initial cost, turbines offer both superior uptime and maintenance cost per Kw-hr, which, depending on the characteristics of use, may result in a lower total cost of ownership. Finally, turbines have much lower noise emissions than reciprocating engines, which is growing in importance as urban sprawl is reducing distance between prime mover locations and that of densely populated areas.

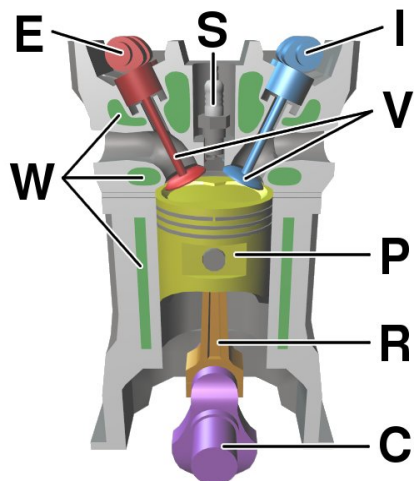
Reciprocating air compressors are positive displacement machines, meaning that they increase the pressure of the air by reducing its volume. This means they are taking in successive volumes of air which is confined within a closed space and elevating this air to a higher pressure. The reciprocating air compressor accomplishes this by a piston within a cylinder as the compressing and displacing element. (Source. www.engineeringtoolbox.com)

Centrifugal compressors produce high-pressure discharge by converting angular momentum imparted by the rotating impeller (dynamic displacement). In order to do this efficiently, centrifugal compressors rotate at higher speeds than the other types of compressors. These types of compressors are also designed for higher capacity because flow through the compressor is continuous. (Source. www.engineeringtoolbox.com)

Generators convert the mechanical energy produced by engines, into electrical power. Electrical power is needed for lighting, switches and to power electrical engines, as well as to power living quarters.

Transmissions provide speed and torque conversions from a rotating power source to another device. Often, the rotational speed of the power source is different from that which is required by the end device. Transmissions, through gear ratios, are used to adapt rotational speed and torque between the power source and receiving device.

Figure 78. Reciprocating Engine

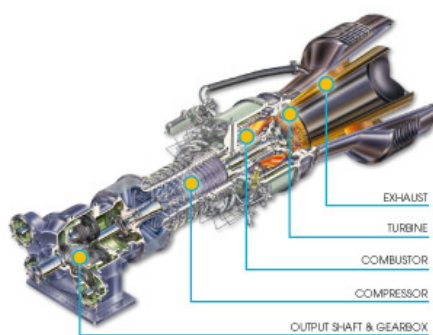


Source: Source: Wikipedia

P – Piston

C – Crankshaft

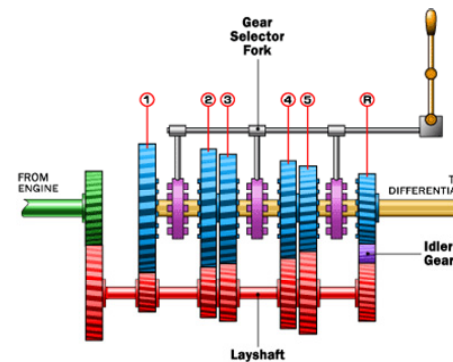
Figure 79. Gas Turbine



Titan 130
Single Shaft Gas Turbine for
Power Generation Applications

Source: Solar Turbine

Figure 80. Transmission

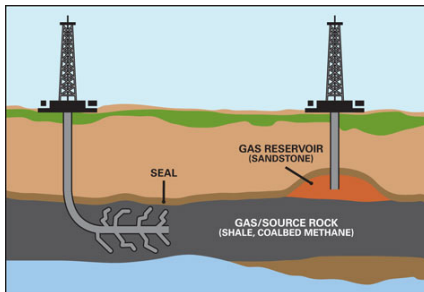


Source: Citi Investment Research and Analysis

Oil & Gas Extraction and Distribution

Oil and gas exploration begins with the search for hydrocarbon-bearing rock formations utilizing geological surveys. After identifying potentially promising areas further tests can be performed to gain insight into the probability of locating hydrocarbons at the site. These advanced techniques include seismic surveys, magnetometers, and gravimeters.

Figure 81. Directional vs. Vertical Drilling



Source: Citi Investment Research and Analysis

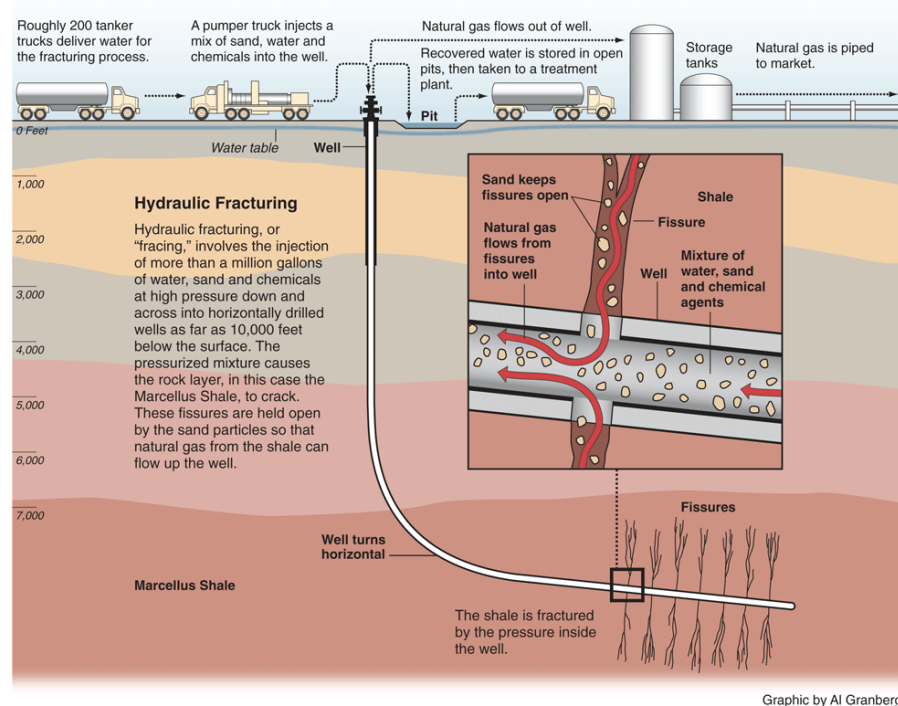
After identify areas of promise, exploratory drilling commences to confirm the presence of hydrocarbons and estimate both internal reservoir pressure and total recoverable hydrocarbons. Onshore rig platforms include a derrick, drilling mud equipment (including mud pumpers and mixers), power generators, and cementing equipment along with hotel facilities for the crew as the drilling sites are typically in remote locations. As drilling progresses, well casing (pipe) is installed in the well and cemented into place. This increases well stability, protects the casing from corrosion and protects underground aquifers from pollution.

If the exploratory drilling is unsuccessful in locating hydrocarbon reserves, the drill module is disassembled and moved to its next location. However, when exploratory drilling successfully reveals the presence of commercially attractive quantities of recoverable hydrocarbons more wells are drilled to quantify the total potential find. Advances in drilling technology now allow for directional (nonvertical) drilling which reduces land use and, along with hydraulic fracturing, has made the recovery of shale hydrocarbons economically feasible.

After appraisal is complete, additional production wells are drilled to recover the hydrocarbons. The number of wells drilled is a function of the size of the reservoir, with larger fields requiring hundreds of wells. As production progresses internal well pressure may decline thereby reducing the rate of hydrocarbon flow. The decline rate of a hydrocarbon well is the rate at which hydrocarbon production will decline from initial output levels. In response to declining internal well pressure multiple advanced recovery techniques have been developed to provide the additional lift needed for recovery. For petroleum formations lifting equipment may be used to help lift the petroleum to the surface. The most common lifting method is rod pumping and uses a surface pump to move a cable and rod up and down in a well which provides the necessary lifting pressure to bring the oil to the surface. Reinjecting gas to repressurize the well is another method used and often requires drilling additional wells called injection wells.

Hydraulic fracturing is another method of advanced recovery. Hydraulic fracturing is a technique used to make shale rock more porous to allow hydrocarbons to flow into the well. Once the drilling is completed fracturing fluids are pumped into the well at high pressures creating fissures in the shale. These fissures allow the trapped oil and gas to flow freely from the rock into the well. To keep the fissure open after the injection has stopped, sand is usually mixed with the fracturing fluid.

Figure 82. Hydraulic Fracturing



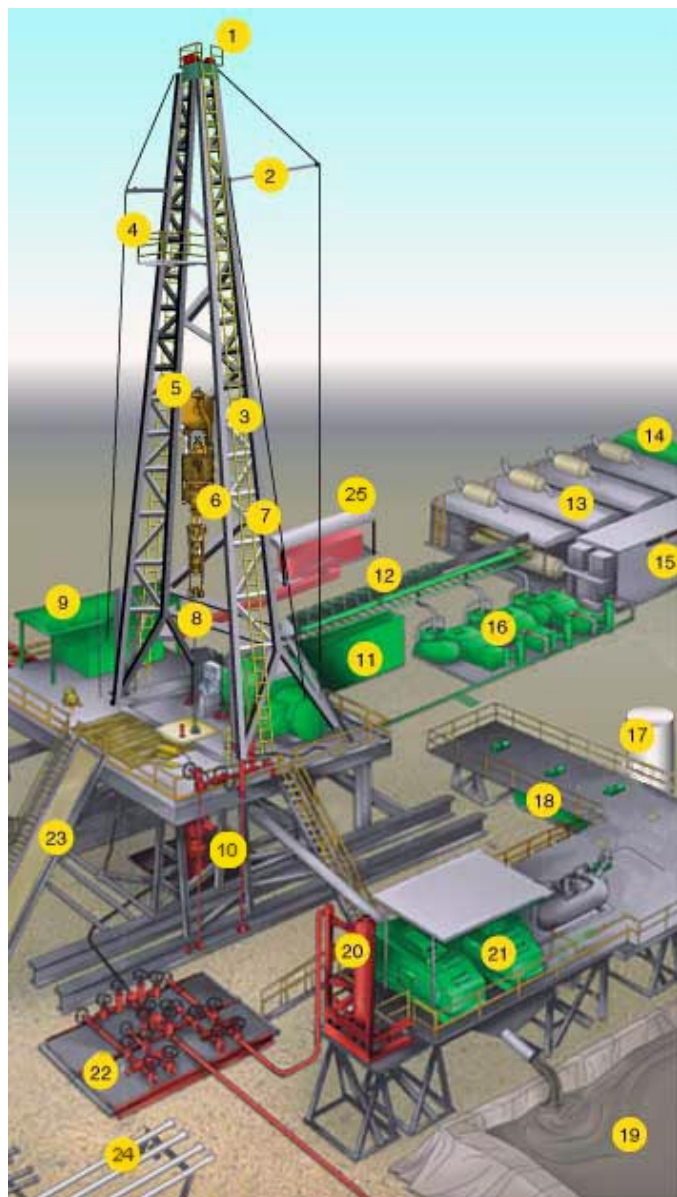
Source: ProPublica

During the production process, wells often require workovers, to repair the well and reconnect to the hydrocarbon. Workovers are completed to restore, prolong, or enhance well production. Workover operations are completed using coiled tubing equipment and include activities such as acidizing.

After the hydrocarbons have been lifted to the surface they are transported to a production facility that separates the oil, gas, and water.

Every stage of oil and gas production and distribution utilizes some combination of engines, turbines, and transmissions. One example is provided in the following drilling rig diagram that illustrates the suite of engine generators needed to power all of the activities of an onshore drilling rig.

Figure 83. Drilling Rig



Source: U.S. Department of Labor

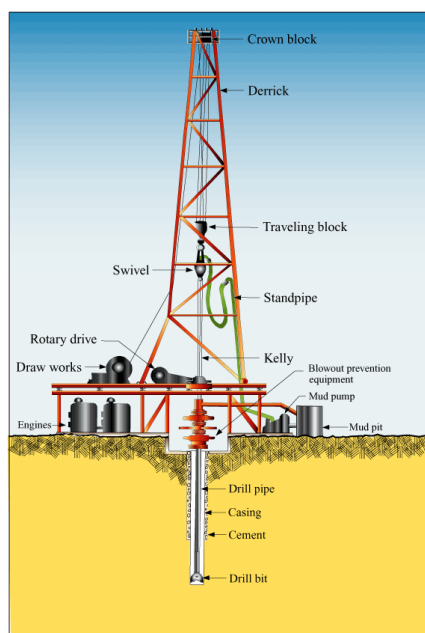
Figure 84. Drilling Rig Components

1. Crown Block and Water Table
2. Catline Boom and Hoist Line
3. Drilling Line
4. Monkeyboard
5. Traveling Block
6. Top Drive
7. Mast
8. Drill Pipe
9. Doghouse
10. Blowout Preventer
11. Water Tank
12. Electric Cable Tray
- 13. Engine Generator Sets**
14. Fuel Tanks
15. Electric Control House
16. Mud Pump
17. Bulk Mud Components Storage
18. Mud Pits
19. Reserve Pits
20. Mud Gas Separator
21. Shale Shaker
22. Choke Manifold
23. Pipe Ramp
24. Pipe Racks
25. Accumulator

Source: Citi Investment Research and Analysis

This report is segregated into four pieces, including drilling, well servicing, production and compression. The first three sections are in approximate order of their chronological occurrence in the E&P process. Compression differs from the other E&P activities in that it is used in upstream, midstream, and downstream applications and is best understood when discussed separately.

Figure 85. Drilling Rig

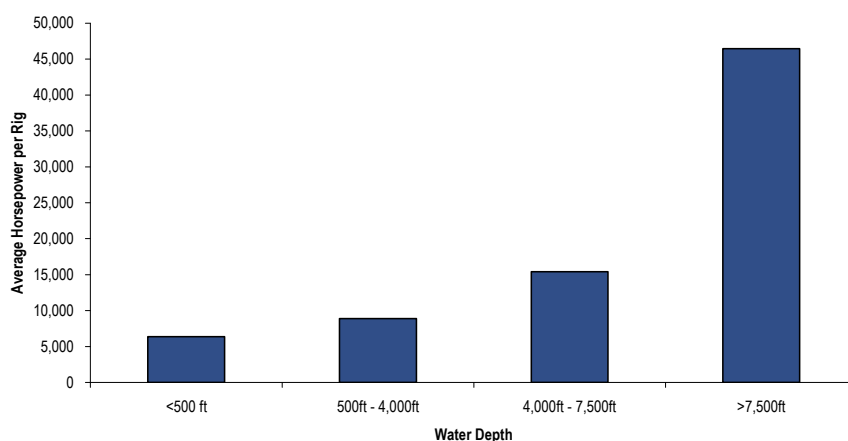


Source: Citi Investment Research and Analysis

Drilling

Drilling is simply the process of creating the well in order to recover hydrocarbons and regardless of the type of drilling (onshore conventional, onshore unconventional, offshore shallow, offshore deep) engines are required to power the rig. Recent advances in drilling technology have made previously inaccessible deposits, accessible. However, accessing these increasingly complex hydrocarbon reserves also requires higher horsepower.

Figure 86. Average Horsepower per Rig



Source: RigBase

Drilling rigs are either mechanical or electric. Mechanical rigs power rig equipment (drawworks, rotary table or top drive, and mud pumps) directly through a clutch or torque converter, while electric rigs use engines to power generator sets.

Onshore Drilling

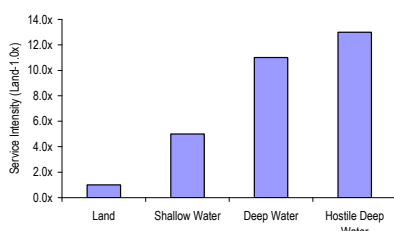
Onshore drilling requires power not only for drilling applications, but also to power mud pumps and other drilling related applications. Because drilling sites are often in remote locations, power is also needed for the living quarters. Conventional hydrocarbons that were found at relatively shallow depths could be developed with 500 hp to 1000 hp vertical rigs. However, as onshore E&P activities have transitioned to unconventional hydrocarbons, the needed rig power has also increased, with many of the newly constructed rigs exceeding 2,000 hp. The increased power needs are a direct function of the length of wells, particularly the lateral section. As onshore drilling has moved away from developing conventional wells, which were often found at relatively shallow depths and could be developed with rigs toward developing unconventional hydrocarbons, the rig's required power has increased. This is largely a function of the increasing length of the lateral (horizontal component of the well bore).

Figure 87. Change in Lateral Length and Number of Stages

		Average HHP	Lateral Length	Number of Stages	Average AFE
Marcellus	2008	6K	3,000 ft	7	\$3.4MM
	2010	30K	5,000 ft	15	\$5.2MM
Bakken	2008	12K	6,500 ft	5	\$3.9MM
	2010	14K	8,500 ft	17	\$6.6MM
Eagle Ford	2008	18K	0 ft	3	\$5.5MM
	2010	36K	6,000 ft	14	\$8.2MM
Permian	2008	12K	3,500 ft	8	\$3.5MM
	2010	30K	4,500 ft	12	\$5.5MM

Source: Company Reports

Figure 88. Offshore Drilling Service Intensity



Source: Halliburton

Offshore Drilling

Regardless of water depth, offshore rigs require a reliable source of electrical power, which is typically provided by a suite of reciprocating engines or turbines. Some of the rigs currently under construction employ a combination of engines and turbines as turbines are best used as providers of constant power while engines are better suited for applications requiring highly variable loads. In addition to powering the living quarters for hundred(s) of workers, depending on the rig design, power is needed for propulsion, drilling, operating the mud pumps, and drawing applications. Power is also needed for utility functions such as energy intensive water desalinization. The demands on the rigs power source are further complicated by the fact that offshore rigs operate in harsh environments, including highly corrosive salty air and wide swings in temperature and humidity. Regardless of the environment, rig operators demand reliable power sources because the opportunity cost associated with loss of power is huge. Offshore drilling rigs are roughly categorized into three categories which are jack-ups (shallow water), semi-submersibles (medium, deep, and ultra deep water), and drill ships (deep and ultra deep water). Alternatively, rigs are also classified by the water depth in which they can operate with the newest drill ships capable of operating in depths of 12,000 feet or more.

Figure 89. Jack-up



Source: Company Reports

Figure 90. Semi-Submersible



Source: Company Reports

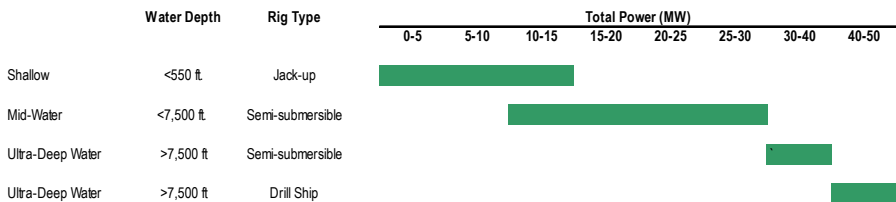
Figure 91. Drill Ship



Source: Company Reports

As illustrated in the following chart, drilling rig power requirements increase with depth. At a depth of 5,000 feet, the water is 41 degrees Fahrenheit, while oil gushes out of the ground at nearly boiling temperatures. In addition, the underground reservoirs are under enormous pressure and create the risk of blowouts, where hydrocarbons shoot upward in an uncontrolled explosion. To prevent this, pressurized drilling fluids are forced into the borehole. The drill fluid pressure must be equal to the pressure of the hydrocarbons surging upward.

Figure 92. Offshore Drilling Rigs - Main & Emergency Power Requirements



Source: Company Reports and CIRA

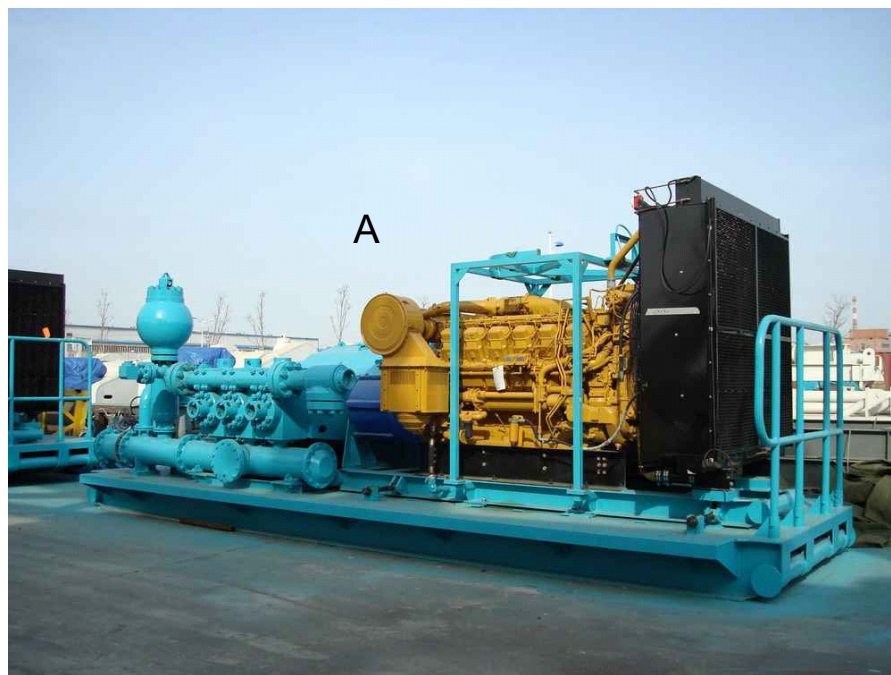
Well Servicing

As defined by Schlumberger, well servicing consists of a range of procedures performed on wells after they have been completed and production has started. These procedures are used to connect damaged wells to the hydrocarbon reserve, restore well pressure and increase recovery rates. For purposes of this note, we are expanding Schlumberger's definition of well servicing to include some activities, such as cementing and mud pumping that are used during the drilling stage.

Mud Pumping

Clearing the well of drilled debris is an important part of the drilling process and is accomplished by pumping heavy fluids, called drilling muds, down the drill pipe (stem), out the drill bit and then back to the surface carrying with them the drill cuttings. The delivery of drill muds is accomplished through a high pressure pumper that requires a high power engine. A picture of a mud pumper, complete with a Caterpillar 3512 engine is provided below.

Figure 93. Mud Pump



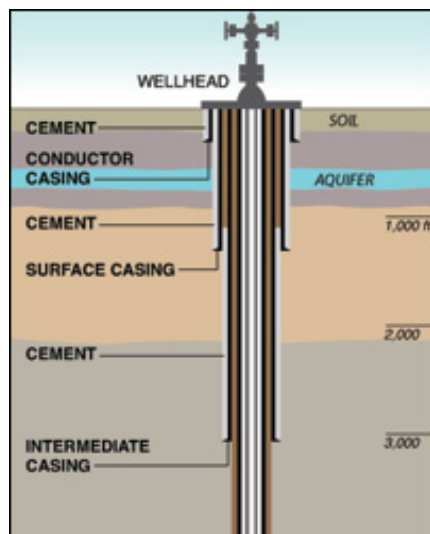
Source: Citi Investment Research and Analysis
A: Caterpillar 3512 Engine

Mud pumper power requirements have been increasing for both onshore and offshore drilling. In the case of onshore, power requirements are changing as directional drilling becomes more prominent. During horizontal drilling a large volume of solids need to be removed from the well, which requires a stronger mud pump. Also, power requirements for mud pumps increase with the length of the well.

Offshore mud pumping demands have also increased due to the greater depths being drilled. At a depth of 5,000 feet, the water is 41 degrees Fahrenheit, while oil gushes out of the ground at nearly boiling temperatures. In addition, the underground reservoirs are under enormous pressure and create the risk of blowouts, where hydrocarbons shoot upward in an uncontrolled explosion. To prevent this, pressurized drilling fluids are forced into the borehole. The drill fluid pressure must be equal to the pressure of the hydrocarbons surging upward. Halliburton expects average drilling depths to continue to increase. The company is forecasting that average deepwater depth will increase by ~5,000 feet over the next three years, which is an increase in length of 20% to 25%. Balancing well pressure becomes more challenging as depth is increased.

The Macondo oil spill illustrates the dangers associated in dealing with the high pressure levels found in offshore deepwater wells. The oil spill started when highly pressurized methane gas shot up from the well and out of the drill column. This gas expanded on the platform of the Deepwater Horizon (deepwater semi-submersible drilling unit), ignited and exploded and completely engulfed the platform in flames.

Figure 94. Casing



Source: Pro Publica

Cementing

When the well reaches a certain depth, the drill pipe is removed and larger diameter pipe (casing) is inserted in the well and permanently cemented in place. Pumping cement into the well provides needed well stability to prevent cave ins and protects the casing from corrosion. In addition, the added well strength allows drilling to continue on to greater depths. Cementing also protects the underground fresh water from being contaminated. Cementing unit power requirements increase with well depth but cementing a well requires less power than fracturing or acidizing. Onshore cementing is usually performed with trucks equipped with two engines.

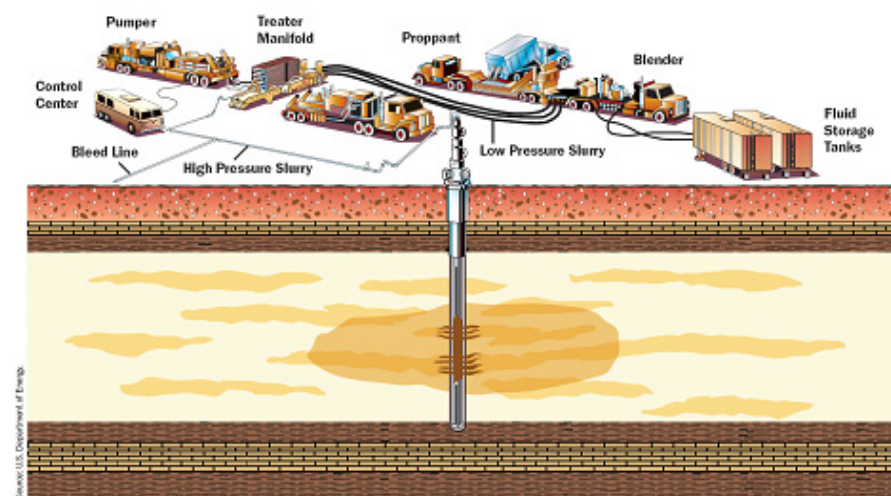
Figure 95. Double Pump Cementing Unit



Source: Jereh Petroleum Equipment Technologies
Deck Engine: CATC15
Auxiliary Engine: CAT CY

Hydraulic Fracturing

Figure 96. Hydraulic Fracturing Site



Source: U.S. Department of Energy

Hydraulic fracture stimulation, or hydraulic fracturing, is the process of fracturing shale rock layers in order to create seams that facilitate the flow of hydrocarbons into the well. The hydraulic fracturing process creates several opportunities for engine sales. The main components of a fracturing rig (illustrated below) are the engine, transmission, and pump. Hydraulic fracturing requires pressure up to 15,000 psi and can use as many as 40 frac rigs, each equipped with a 2,500 hp frac pump to produce the required pressure. The fracturing process places heavy loads on the frac pump engines given the high level of pressure needed to crack the shale formations, which both shortens the engine's life, but also creates a large aftermarket revenue stream. Instead of replacing engines, some frac rig operators choose to rebuild engines, which would benefit the likes of Cummins' Distributor base. Rebuilt engines tend to have a useful life that is roughly 60% of a new engine and require a higher maintenance. Transmissions are also an important component of the rig and serve a dual function of both controlling the power delivered to the pump, and separately controlling the rig while it is being driven between locations. Blenders are also needed during the fracturing process to mix the fracturing fluids, which consist of water, chemicals, and sand.

Figure 97. Major North American Fracturing Rig & Component OEMs

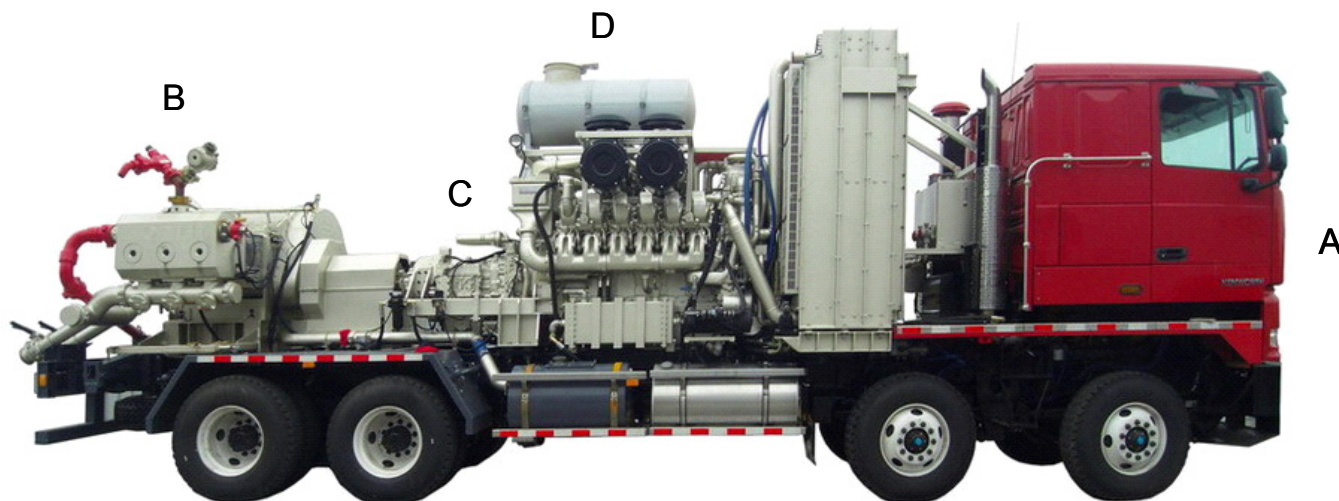
Engines	Transmission	Pumps	Rigs
Caterpillar	Allison	Axon Energy Products	Mack
Cummins	Caterpillar	FMC Technologies	Navistar / Caterpillar
MTU Detroit Diesel ⁽¹⁾	Cummins	Frac Tech	Paccar
	Twin Disc	Gardner Denver	
		Halliburton	
		Phoenix Global	
		Weir	

Note: Boxes indicate product still in development.

1) MTU Detroit Diesel is a subsidiary of Tognum who is jointly owned by Daimler and Rolls Royce.

Source: Company Reports and CIRA Estimates

Figure 98. Hydraulic Fracturing Rig



Source: Jereh Petroleum Equipment Technologies

A: Truck Engine

B: Hydraulic Fracturing Pump

C: Transmission

D: Frac Engine

Other Well Servicing Procedures

Other well servicing activities that are powered by engines include the following:

Drawworks - During the drilling process the drill stem needs to be raised and lowered several times in order to add additional joints of drill pipe, insert permanent well casing or to replace a dull drilling bit. The rig's hoisting system, which incorporates both engines and transmissions, is used to raise and lower the drill. This is also called drawing and is accomplished with the draw works.

Acidizing - Acidizing services reconnect the well to the hydrocarbon reserves by pumping acid washes, or acid fracturing into the well to remove impediments. This activity requires engines to power the pumps that deliver the acid wash.

Nitrogen Services - Nitrogen services are used in well construction, pipeline and industrial services. Nitrogen, an inert gas, is used to circulate wellbores, stimulate well bores, foam cement slurries, purge and test pipelines and purge and test boilers and pressure vessels. Liquid nitrogen is transported to the jobsite in truck mounted insulated storage vessels. The liquid nitrogen is pumped under pressure via high pressure pump into a heat exchanger. The heat exchanger converts the liquid to a gas at the desired discharge temperature.

Figure 99. Nitrogen Pumper



Source: Jereh Petroleum Equipment Technologies

Coiled Tubing – Coiled tubing has several applications. The first is to for circulation for deliquification of gas wells. Gas well deliquification refers to technologies that remove water or condensate build-up that is preventing the flow of gas from the well. Circulation consists of inserting coiled tube into the well and than pumping gas through it to circulate out the obstructing liquids. Circulation is also used to clear out accumulations of debris in the well.

Coiled tubing can also be used for pumping applications for delivering fluids to specific locations in the well such as for cementing perforations.

Coiled tubing drilling applications are being developed as well. Compared to traditional drilling techniques that require the drill string to assembled and dismantled by joint, coiled tube drilling is much easier and more time efficient because the coiled tube can be removed and inserted without requiring it to be broken into parts.

Coiled tubing can also be used as production string in shallow gas wells that produce some water due to the fact that that narrow internal diameter of the coiled tubing results in a much higher velocity than that of conventional tubing. This higher velocity helps lift liquids, which may otherwise kill the well flow, to the surface.

Figure 100. Coiled Tubing Unit

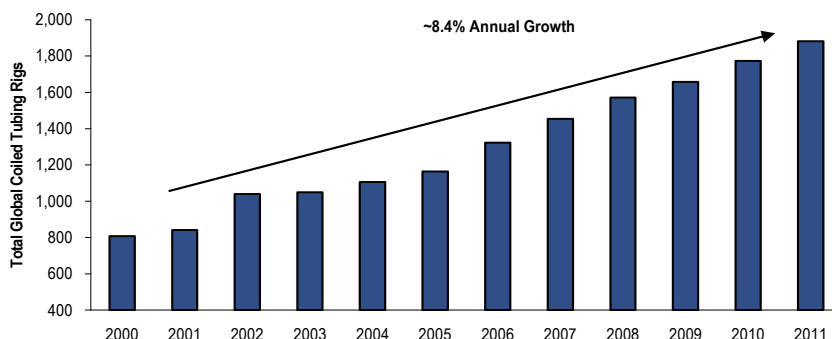


Source: Jereh Petroleum Equipment Technologies

Engine: CATC15

The global fleet of coiled tubing rigs has been growing at ~8.4% per year during the last decade.

Figure 101. Global Coiled Tubing Rig Count



Source: Intervention & Coiled Tubing Association

Offshore Crane – Offshore cranes are used for loading or unloading supplies from the platform as well as for moving items around the platform. These cranes are often powered by an independent engine.

Fire Pump – Fire pumps are used to pump water for fire emergencies. These engines are typically powered by independent engines.

Production

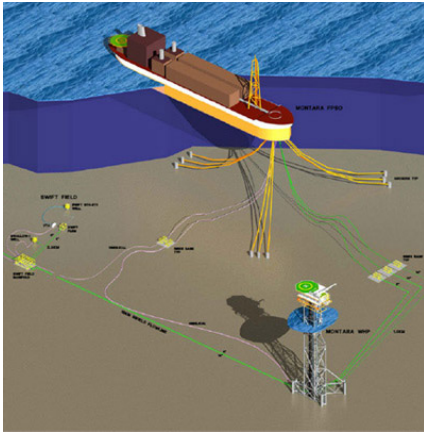
When an oil well is first drilled, the internal well pressure is usually sufficient to lift the hydrocarbons to the surface. However, over the course of the well's life, internal pressure declines and reduces the output flow. One method of stimulating production is by using a pump jack to increase well pressure. Pump jacks convert the rotational energy created by the engine into vertical motion used to move the pump shaft. It is this vertical motion of the pump shaft that increases well pressure and lifts the oil to the surface.

Figure 102. Pump Jack



Source: Citi Investment Research and Analysis

Figure 103. FPSO



Source: Citi Investment Research and Analysis

Floating Production, Storage, and Offloading Units (FPSOs)

Historically, offshore oil production was done by connecting pipelines from the land to the offshore platform. However, as exploration has moved into deeper waters this method is no longer feasible. This has led to the increased use of FPSOs for offshore production. FPSOs produce and store hydrocarbons onboard, and are capable of offloading the hydrocarbons onto shuttle tankers. The processing equipment aboard the FPSO is similar to what would be found atop a production platform and can consist of water separation, gas treatment, oil processing, water injection and gas compression. FPSOs typically use compressors for both gas reinjection for well stimulation as well as for gas lift. Douglas-Westwood, estimates that investment in FPSOs will amount to \$43 billion over the next five years, which implies a very attractive revenue opportunity for manufacturers of diesel engines, gas turbines and compressors. For example, Petrobras recently awarded GE with a \$160 million FPSO contract for two FPSOs. The contract is for eight 31.1 MW gas turbine generator sets and 12 motocompressor trains for the two vessels which will be used for both power generation and compression.

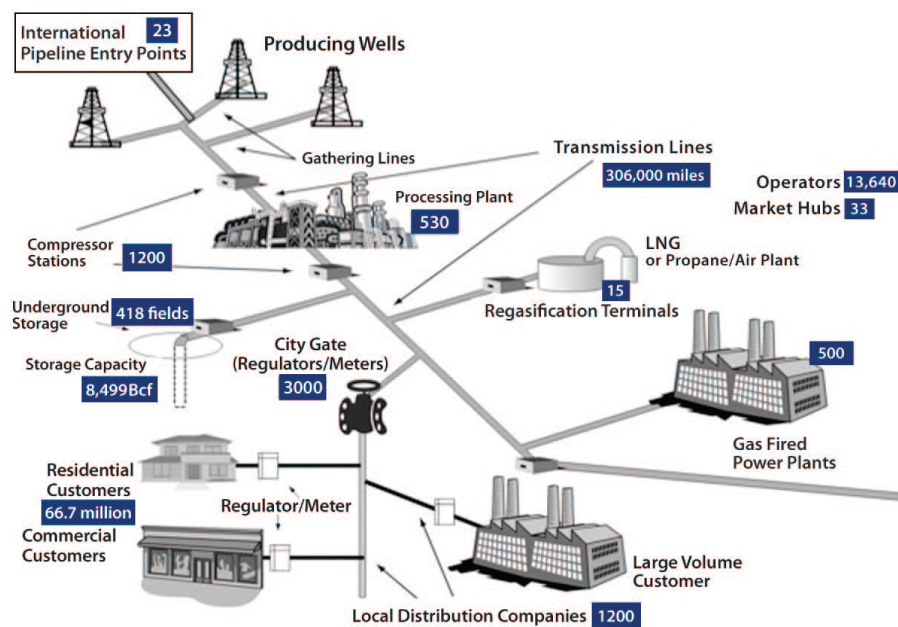
Compression

Natural gas compression is the process of increasing the pressure of natural gas to facilitate its transportation. Compression is utilized in various upstream, midstream, and downstream applications.

Reciprocating air compressors, which are powered by reciprocating engines, are positive displacement machines, meaning that they increase the pressure of the air by reducing its volume. This means they are taking in successive volumes of air which is confined within a closed space and elevating this air to a higher pressure. The reciprocating air compressor accomplishes this by a piston within a cylinder as the compressing and displacing element. (Source. www.engineeringtoolbox.com).

Centrifugal compressors, which are powered by gas turbines, produce high-pressure discharge by converting angular momentum imparted by the rotating impeller (dynamic displacement). In order to do this efficiently, centrifugal compressors rotate at higher speeds than the other types of compressors. These types of compressors are also designed for higher capacity because flow through the compressor is continuous. (Source. www.engineeringtoolbox.com)

Figure 104. Natural Gas Production & Distribution



Source: MIT

Compression – Upstream

Upstream activities, also referred to as Exploration and Production, consist of searching for, recovering and production of hydrocarbons. Upstream compression for natural gas is typically used for wellhead stimulation and gathering.

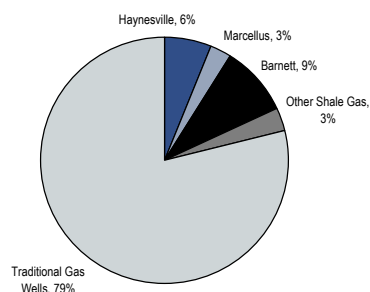
Wellhead Compression - Compression at the wellhead is utilized because, at some point during the life of natural gas wells, reservoir pressures typically fall below the line pressure of the natural gas gathering or pipeline system used to transport the natural gas to market. At that point, natural gas no longer naturally flows into the pipeline. Compression equipment is applied in both field and gathering systems to boost the pressure levels of the natural gas flowing from the well allowing it to be transported to market. Changes in pressure levels in natural gas fields require periodic changes to the size and/or type of on-site compression equipment.

Natural gas Reinjection - Compression is used to re-inject natural gas into producing oil wells to maintain reservoir pressure and help lift liquids to the surface, which is known as secondary oil recovery or natural gas lift operations. Typically, these applications require low- to mid-range horsepower compression equipment located at or near the wellhead. Compression equipment is also used to increase the efficiency of a low-capacity natural gas field by providing a central compression point from which the natural gas can be produced and injected into a pipeline for transmission to facilities for further processing.

Gas Gathering - As gas is produced from the well it is collected in a gathering system. In order to transport this gas from the gathering system to the processing plants, compressors are used to increase gas pressure.

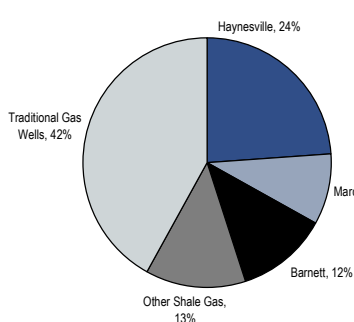
The shifting focus from convention to unconventional sources of natural gas has changed compression demands in several ways. While each well is unique, unconventional wells typically have a higher level of initial internal well pressure, which eliminates the need for compression. However, this internal pressure level can decline rapidly, falling by as much as 80% within the first year of production. At this point in an unconventional well's life, its wellhead compression needs are similar to those of a traditional natural gas well.

Figure 105. Total Onshore Nat Gas Production by Source



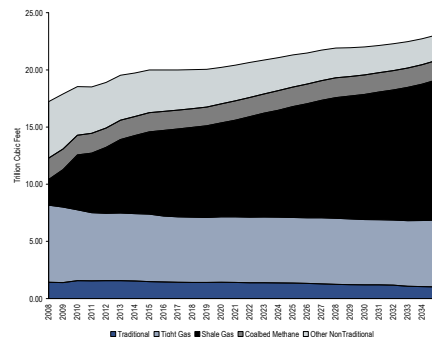
Source: HPDI and CIRA Estimates

Figure 106. New Onshore Nat Gas Production by Source



Source: HPDI and CIRA Estimates

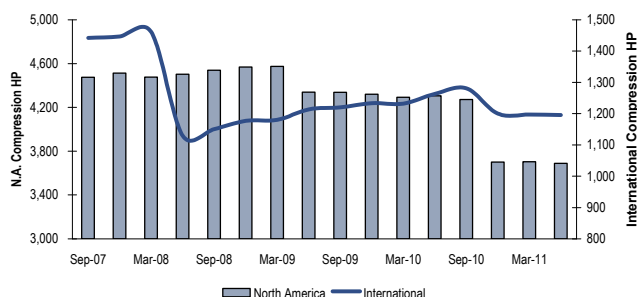
Figure 107. Forecast US Natural Gas Production by Source



Source: EIA

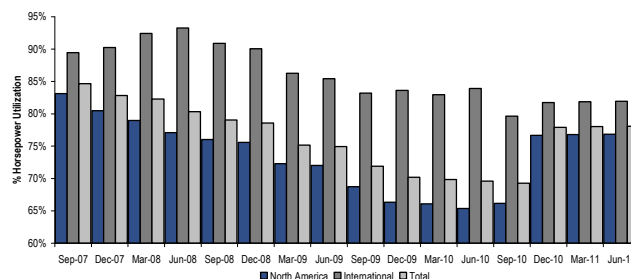
Exterran is the largest provider of leased compressors in North America, and a key customer of CAT's. As evident in the following charts, the company has significantly reduced its North American compressor fleet. This is partially attributable to the reduced need for compression during the early stages of production from unconventional wells. However, the reduced demand for leased compressors is also due to the fact that the larger oil and gas producers are currently the main developers of the unconventional gas reserves, and these companies have their own compressor fleets.

Figure 108. EXH Available Compression



Source: Company Reports

Figure 109. EXH Compression Utilization



Source: Company Reports

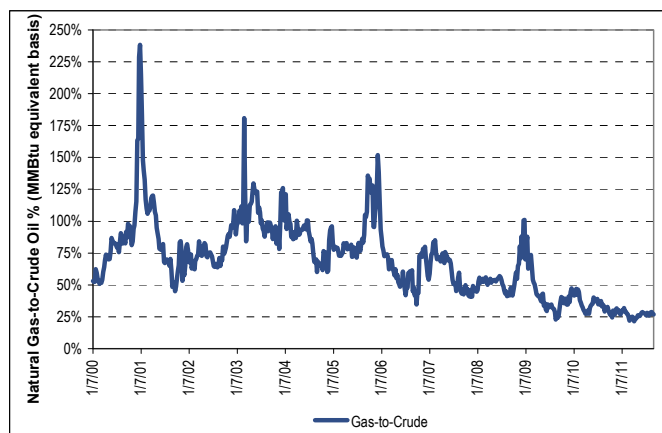
Compression – Midstream

Gas Processing - Gas Processing is the process of separating gas from other liquids lifted from the well and conditioning the gas for further downstream use. The natural gas is compressed and transported by a pipeline for sales gas while the liquids are sent to fractionation trains for further processing. Compression requirements at the plants are typically achieved with large reciprocating compressors driven either by electric motors or gas engines.

Currently, this is an area of notable strength, driven by the high price differential between oil and natural gas prices. This large price spread (crude oil is now ~4x more expensive than domestic natural gas prices on Mmbtu equivalent basis) is driving producers to develop more liquid rich shale plays to get a more oil-like price for their production. This requires significantly more processing capacity in new areas of development. While natural gas prices remain depressed, NGL prices have remained strong with new supplies being consumed by the petrochemical (who have gained a relative cost advantage) and refining industries or being exported out of the Gulf Coast market. Furthermore, in the U.S., over 50% of the components of NGL (such as propane) are priced off crude oil. Separately, this price differential also explains the changing composition of the domestic rig count, as operators are more inclined to drill for oil in versus natural gas. Since the middle of 2009, the oil rig count has increased 5-fold, while the total natural gas rig count has declined almost by half since 2008.

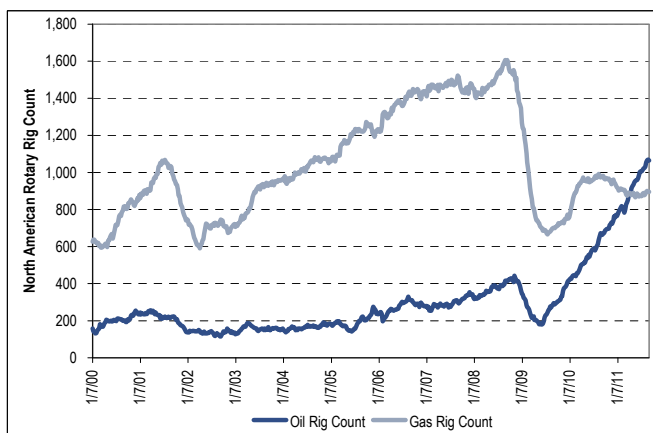
Given the extensive use of (large) compressors used in processing facilities, we see this as an area of near-term upside for the engine / turbine suppliers.

Figure 110. Natural Gas as % of Crude Oil (on MMBtu equivalent basis)



Source: Citi Investment Research and Analysis

Figure 111. North American Rotary Rig Count: Oil vs. Gas (as of 9/2/2011)



Source: Citi Investment Research and Analysis

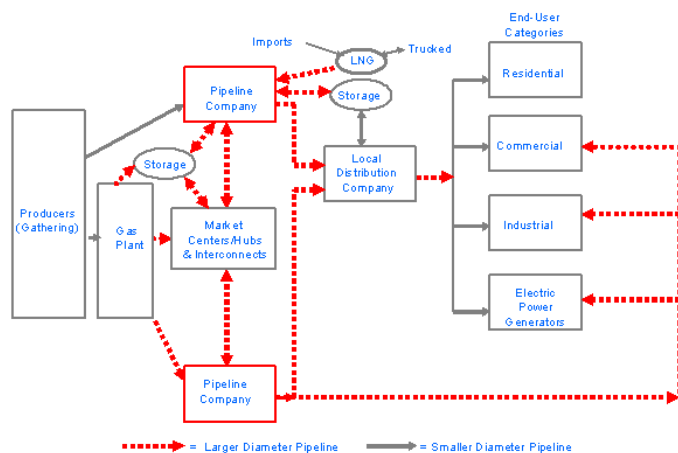
Compression – Downstream

Natural Gas Storage & Withdrawal - Gas Storage / Withdrawal applications assist in balancing the supply and demand of natural gas. Globally, companies in the business of supplying gas to the end users are faced with fluctuating seasonal demand. Winter demands peak in the northern climates when temperatures dip and the demand for natural gas for home heating spikes. The reverse takes place in summer when air conditioning demand peaks, which translates into peak power plant demand. In order to accommodate this rapidly changing demand dynamic, storage and withdrawal of natural gas is continually managed. Storage is achieved by injecting gas at high pressure into underground geological formations using either reciprocating or centrifugal compressors that can be powered by engine or turbine driven. The gas injection season is from April 1 to October 31 and withdrawals start November 1 through March 31.

Transmission - At various stages in the natural gas production and distribution process gas is transported through pipelines. Often, when gas is delivered from the producing area or supply source to the market area, it travels several hundred

miles. The following charts illustrate both the natural gas transmission path and the US natural gas pipeline network. These charts illustrate both the frequency which pipelines are required from gas production through delivery to the final customer as well as the extensive US pipeline network.

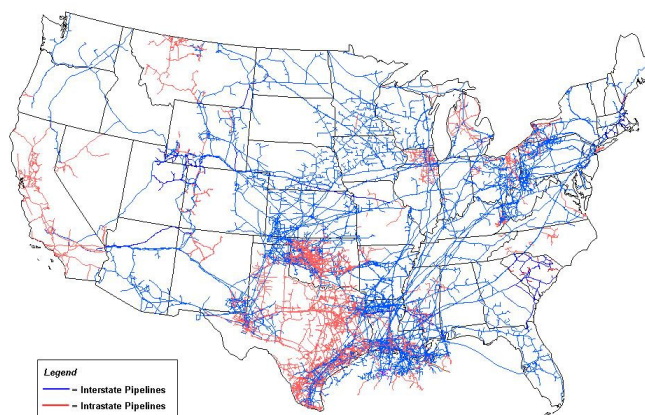
Figure 112. Natural Gas Transmission Path



Source: Energy Information Administration, Office of Oil and Gas

Source: EIA

Figure 113. US Natural Gas Pipeline Network

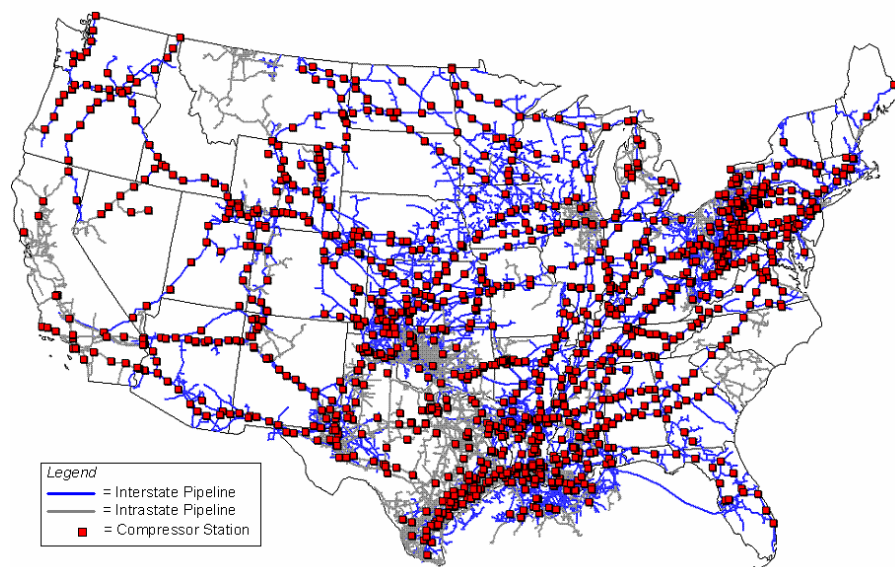


Source: Energy Information Administration, Office of Oil & Gas, Natural Gas Division, Gas Transportation Information System

Source: EI0041

In order to maintain a continuous flow of gas between supply areas and customers, compressor stations are located along the pipeline to maintain pressure of the transported gas. According to the latest EIA estimates, there are more than 1,400 compressor stations located along 305,000 miles of interstate and intrastate transmission pipelines. Compressor stations are typically located at intervals of 50 to 100 miles along the pipeline. The average compressor station is equipped with four compressors, each with average horsepower of 3,590.

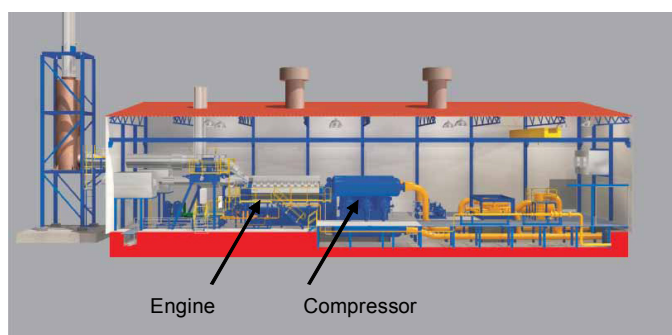
Figure 114. US Natural Gas Compressor Stations



Source: EIA

Compressor units are usually rated at 1,000 horsepower or higher, and are either centrifugal (turbine) or reciprocating (piston) type. Large compressor stations can have 15 units or more with overall horsepower rating from 50,000 to 100,000 HP. Many compressors operate on natural gas taken from the pipeline. Depending on the location of compressor station, the piped gas may or may not be processed. Given this dynamic, OEMs capable of producing compression engines with flexible fuel requirements are at an advantage. In recent years environmental concerns have been driving the increased use of electricity driven compressor units which are linked to the power grid. However, this is only feasible when compressor stations are located in reasonable proximity to the power grid. Compressor stations use either high speed reciprocating engines or turbines to power centrifugal compressors.

Figure 115. Compressor Station



Source: Company Reports and CIRA

Figure 116. Natural Gas Compressor



Source: Jereh Petroleum Equipment Technologies
A: CAT G3608LE Engine

Turbine compressors are fueled with a small proportion of the natural gas that they compress. The turbine itself serves to operate a centrifugal compressor, which contains a type of fan that compresses and pumps the natural gas through the pipeline. Some compressor stations are operated by using an electric motor to turn the same type of centrifugal compressor. This type of compression does not require the use of any of the natural gas from the pipe, however it does require a reliable source of electricity nearby. Reciprocating natural gas engines are also used to power some compressor stations. These engines resemble a very large automobile engine, and are powered by natural gas from the pipeline. The combustion of the natural gas powers pistons on the outside of the engine, which serves to compress the natural gas.

Industry Dynamics

The oil and gas prime mover market benefits from barriers to entry arising from the high cost of equipment failure, high opportunity cost of downtime, and the need for a global aftermarkets service network.

There are several characteristics of the oil and gas sector that create reasonably high barriers of entry for the power solutions market. The applications in the oil and gas industry for which engines and turbines are used have a high cost of failure and downtime, which creates reasonably high switching costs outside of a select few OEMs. For onshore drilling and production operations located in remote locations, as well as offshore applications, the gensets are needed to not only power the various drilling, workover, and production applications but also to power the hotel and utility functions for the crews' living quarters. Additionally, the complexity of exploration and production is increasing as both drilling (onshore and offshore) and offshore operating depth increases. As complexity of accessing the hydrocarbons increases, so to does the associated cost of equipment failure. This is perfectly illustrated by the Macondo accident in the Gulf of Mexico. The Macondo was operating in water depth of ~5,000 feet, which is less than half of the water depth of the ultra deep water sites currently being explored and developed. The Macondo spill started on April 20, 2010 and was not plugged until July 15, 2010. During that time ~4.9 million barrels of oil were spilled into the ocean making Macondo the largest offshore oil spill ever.

Engine and turbine OEMs also have an advantage when the customer is already using their products in its existing fleet. An onshore site will require engines for the genset to power the rig and mud pumps. If the rig is drilling horizontally, additionally engines will be required for the frac rig, and various workover applications. Equipment servicing is easier when all of the engines are provided by one OEM. Furthermore, if the fleet's existing engines have been reliable and received a high quality level of aftermarkets service, then the OEM of the existing engines is well positioned for any new orders.

Turbine OEMs are also capitalizing on their installed base by designing higher power turbines with an identical frame size as older, lower power installed turbines. For example, Solar's Titan 250 gas turbine has the same footprint as the Titan 130 yet produces 50% more power. MAN Diesel & Turbo is pursuing a similar strategy with its THM family of turbines, all of which have the same size frame, which enables MAN to be able to upgrade its installed base simply by swapping engines. These upgrade solutions provide CAT and MAN a sizeable competitive advantage in maintaining their installed base, because of the cost savings provided to customers interested in upgrading compressor station capacity.

In addition to product reliability, aftermarket service quality is potential lever for differentiation. E&P companies operate globally, and demand high quality aftermarket service regardless of the location. CAT's global service footprint allows them to guarantee this service due to its 1,200+ global dealer locations as well as its engine manufacturing facilities that are located on five continents. This global footprint is a significant advantage in attracting new orders, especially as areas of exploration are in increasingly remote locations. Cummins is also using its global footprint and huge distributor base to their advantage by having their knowledgeable oil and gas distributors from Texas train distributors in other geographies to bring them up the learning curve faster. As mentioned earlier, we are seeing a similar dynamic from global energy companies such as CNOOC, which has made two major investments alongside Chesapeake in North American shale resources partially to accelerate its development of the necessary technological capabilities (horizontal drilling, fracturing, etc) needed to develop reserves in China.

Several trends create the potential for shifts in market share among industry participants including demand for engines with longer maintenance cycles in the fracturing market and forthcoming emissions regulations.

Technological innovation can be another differentiating factor. Offshore drillships can burn 40,000 gallons of diesel fuel a day and fuel costs can contribute up to 80% of total operating expenses. OEMs that develop more fuel efficient power solutions will be in a more favorable position, all things equal. One example of the importance in maximizing performance is demonstrated by Siemens' efforts to upgrade its portfolio of gas turbines that produce less than 50 MW of power. This line of turbo's was acquired from Alstom in 2003. Since the acquisition Siemens has worked to upgrade these turbines by incorporating in-house technology as to improve their fuel efficiency, power, and up time. Given the high upfront cost of acquiring turbines, even small improvements in fuel efficiency and maintenance cycle can have a meaningful impact on total cost of ownership.

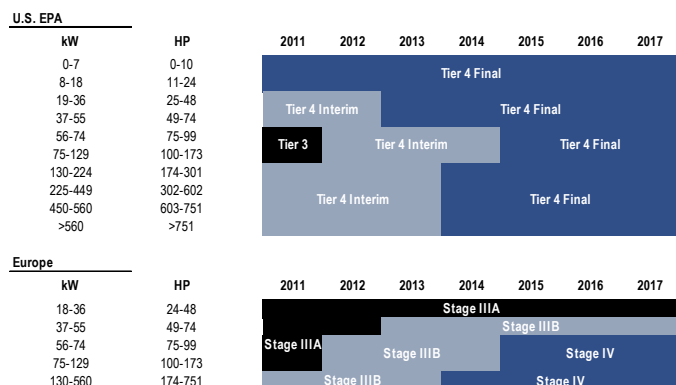
Advances in drilling and production technology, especially the advent of hydraulic fracturing stimulation, have created the potential for shifts in market share among existing OEMs of prime movers and other components. During the fracturing process, frac rig engines receive a level of stress commensurate with a level equal to several months of operations in more traditional E&P applications. This stress collapses the frac rig's maintenance cycle resulting in a higher rate of machine downtime while rig components are repaired and replaced. This forces frac rig operators to make significant investments in stand by rig capacity to avoid shutting down operations, which has a very high opportunity cost. OEMs capable of producing frac rig components with longer maintenance life cycles should be able to demand premium pricing due to the cost savings these products would create for frac rig operators in the form of a reduction in size of the total required fracturing rig fleet.

Increasing emissions regulations also present opportunities for engine OEMs to improve their competitive positioning by developing the most efficient solutions for compliance with more stringent emissions regulations. The International Maritime Organization's (IMO) MARPOL 73/78 Annex VI has established emissions regulations for marine diesel engines with power greater than 130 kW. IMO TII went into effect in January 2011 and requires a 20% reduction in NOx for vessels with a keel-laid date on or after January 1, 2011. IMO Tier III, effective January 2016, requires a further 74% reduction in NOx compared to Tier II levels. Currently, North America is the only NOx Emissions Control Area requiring adoption of IMO TII and TIII standards but other control areas are expected to adopt the requirements in coming years.

Off-highway emissions regulations are primarily focused on removing particulate matter (PM) and oxides of nitrogen (NOx). By 2014, EPA 4 Final, and EU Stage IV regulations require a greater than 90% reduction in both PM and NOx from their current levels.

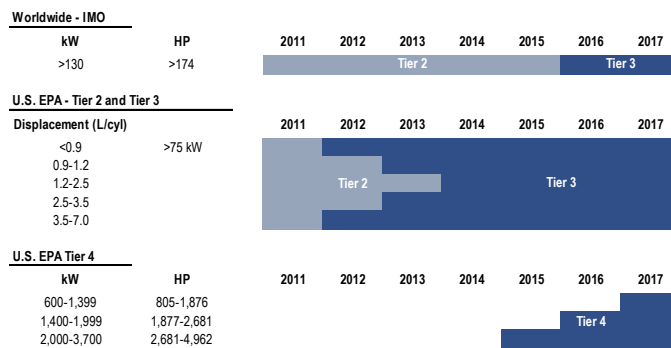
On-highway emissions regulations have provided opportunities for increased differentiation among engine OEMs, with companies such as Cummins being able to leverage their in house R&D expertise to create preferred solutions and thereby capture incremental market share. In addition to capturing share, Cummins has also increased its components segment revenue by helping other OEMs develop emissions solutions.

Figure 117. Off-Highway Emissions Timetable



Source: Company Reports

Figure 118. Marine Emissions Timetable



Source: Company Reports

Emissions regulations have also introduced a new risk to engine OEMs from a competing technology, electric engines. As compressor stations and gas sites are located increasingly closer to residential areas, there is a growing emphasis on reducing both emissions and noise pollution which favors electrical engines. If electrical engines begin to capture meaningful market share we would expect the diesel and gas engine OEMs to pursue acquisitions in order to acquire the technology. ABB and Siemens currently manufacture electrical engines for compression.

Caterpillar Inc.

(CAT.N; US\$83.96; 2M)

Valuation

Our \$95 price target for Caterpillar is derived by using a P/E valuation.

Analyzing trading patterns for the past ten years, we find Caterpillar's shares have traded at an average P/E of 14.4x forward EPS. The differing geographic and business mix that CAT will have going forward after its acquisition of Bucyrus would argue for a slightly higher multiple. However, CAT's P/E has tended to trend lower as economic cycles progress, arguing for a lower multiple. Given the increasingly uncertain economic outlook, we expect the company's valuation to reflect an increased risk premium and are applying a below average P/E multiple of 10.5x to our 2012 EPS estimate to arrive at our price target.

Risks

We rate the shares of Caterpillar Medium Risk. CAT has a high beta of 1.61, and has higher volatility of earnings than other machinery companies. It is rated A2/A with a stable outlook, allowing the company and its finance subsidiary to issue commercial paper into the A1/P1 market. Among the other reasons for a Medium Risk rating are:

- **Construction market downcycle could persist beyond 2011** — CIRA's economic forecasts foresee a decline in U.S. non-residential construction (1/3 of all U.S. construction spending) through 2011, and construction in European economies (normally at a lag to the U.S.) could decline into 2011. Furthermore, state & local government funding for construction (the biggest portion of US construction spending) will likely decline in 2011 due to the severity of budget deficits and decline in gas tax revenue. While residential construction is expected to pick up in 2011 from current trough levels, demand for construction equipment will likely be soft for the next few years until the above-mentioned sectors recover.
- **Late-cycle engine business may dampen recovery for Caterpillar in 2011.** Engine purchases tend to have long lead times between order and delivery, especially for Cat's Solar Turbine business. 2009 was a solid year for this business based on orders from prior years, and 2010 has been better than expected. However, declining gas prices and the Gulf of Mexico drilling moratorium could negatively impact the largest of CAT's engine businesses in 2011.
- **Pension plan could require further funding** — Caterpillar's consolidated pension plans are underfunded as a result of the sharp decline in world equity markets and the fall-off in discount rates. The company has contributed over \$1bn to its plan in 2010, but it may need to contribute additional amounts in the future if the company's discount rate (based on corporate bond yields) continue to decline.

If these risks prove to have less of an impact on Caterpillar than we believe, the stock could surpass our target price.

Conversely, should the economy recover faster than we expect, machinery and engine sales and profitability could improve earlier than we forecast. Furthermore, a recovery would likely also help improve the funding position for Caterpillar's pension plan. In this case, the stock could easily exceed our target price. On the other hand, a harder impact from the risks listed above could cause the stock to fail to reach our target.

Cummins Inc.

(CMI.N; US\$88.15; 1M)

Valuation

Our \$115 price target for Cummins is derived by using a P/E valuation.

Over the past 15 years, cutting across two-plus cycles, Cummins has traded on average at 14.4x one-year forward earnings, and as low as 8-9x at peak periods. While Cummins' current business/geographic mix is more attractive relative to historical experience (including a substantial and growing share of earnings derived from key emerging markets), and the company's balance sheet has also meaningfully improved of late (with net cash as of 2Q end of ~\$3.67 / share), given our positioning in the later portion of the current economic cycle, we use a lower one-year forward multiple of 11.3x against 2012 EPS of \$10.20 to derive our \$115 target.

Risks

We rate the shares of Cummins Medium Risk. We highlight the following risks:

- **Further moves toward backward integration.** The North American truck industry has historically used externally sourced engines from independent engine makers like Cummins. Brand loyalty by customers and the high residual value associated with these independent engines sustained their strong market shares despite attempts by manufacturers to increase vertical integration. Recently, however, North American manufacturers are starting to migrate towards the European model of backward integration: Among other moves, Navistar and PACCAR decided to build their own engines in the U.S. and install them in North American heavy-duty trucks.
- **Inherent volatility in end-markets.** The primary end-markets into which Cummins sells to are highly cyclical, particularly heavy-duty truck markets worldwide. Given the company's high degree of fixed cost leverage, a marked downturn in one of these end-markets could result in sharp decline in profitability relative to our outlook.

The above risks could prevent the shares from attaining our target price.

Appendix A-1

Analyst Certification

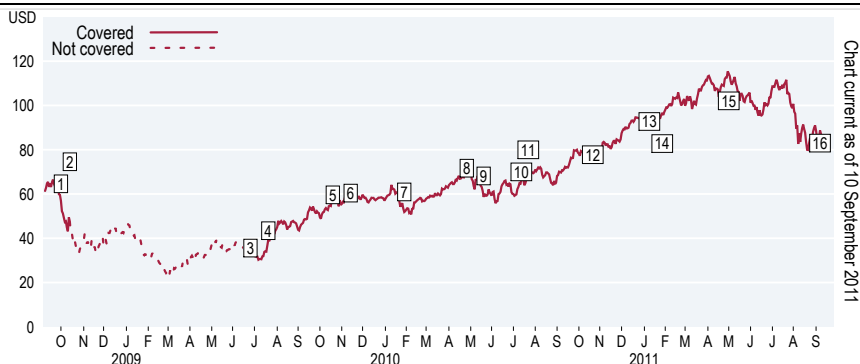
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Caterpillar Inc. (CAT)

Ratings and Target Price History Fundamental Research

Analyst: Timothy Thein, CFA
Covered since June 25 2009



Date	Rating	Target Price	Closing Price
1 1-Oct-08	1M	*72.00	56.95
2 14-Oct-08	Coverage terminated		
3 25-Jun-09	*2H	*36.00	34.49
4 21-Jul-09	2H	*42.00	39.46
5 20-Oct-09	2H	*62.00	59.61
6 13-Nov-09	2H	*64.00	58.78

* Indicates change

Date	Rating	Target Price	Closing Price
7 28-Jan-10	2H	*60.00	51.86
8 27-Apr-10	2H	*80.00	68.53
9 20-May-10	2H	*68.00	58.67
10 13-Jul-10	2H	*71.00	66.79
11 22-Jul-10	2H	*78.00	68.00
12 21-Oct-10	2H	*85.00	78.89

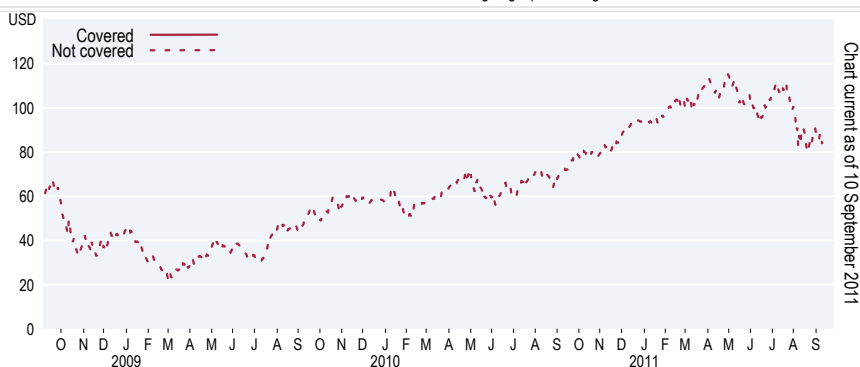
Date	Rating	Target Price	Closing Price
13 10-Jan-11	*2M	*100.00	93.39
14 27-Jan-11	2M	*108.00	96.63
15 1-May-11	2M	*124.00	115.41
16 7-Sep-11	2M	*95.00	88.69

Rating/target price changes above reflect Eastern Standard Time

Caterpillar Inc. (CAT)

Ratings and Target Price History Best Ideas Research Relative Call (3 Month)

Analyst: Timothy Thein, CFA
Covered since June 25 2009



* Indicates change

Rating/target price changes above reflect Eastern Standard Time

Cummins Inc. (CMI) Ratings and Target Price History Fundamental Research

Analyst: Timothy Thein, CFA
Covered since June 25 2009

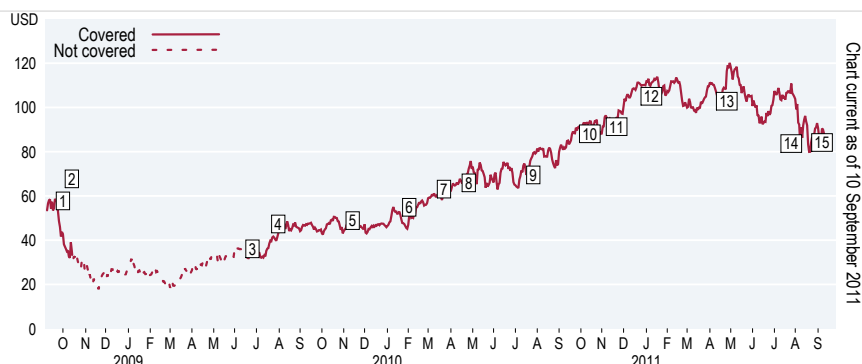


Chart current as of 10 September 2011

	Date	Rating	Target Price	Closing Price
1	1-Oct-08	*1M	*\$59.00	42.77
2	14-Oct-08	Coverage terminated		
3	25-Jun-09	1M	*\$40.00	34.26
4	31-Jul-09	1M	*\$47.00	43.01
5	13-Nov-09	1M	*\$53.00	46.97

* Indicates change

	Date	Rating	Target Price	Closing Price
6	2-Feb-10	1M	*\$58.00	51.09
7	23-Mar-10	1M	*\$72.00	62.35
8	27-Apr-10	1M	*\$83.00	72.40
9	27-Jul-10	1M	*\$92.00	79.43
10	14-Oct-10	1M	*\$107.00	93.76

	Date	Rating	Target Price	Closing Price
11	21-Nov-10	1M	*\$110.00	94.31
12	10-Jan-11	1M	*\$126.00	111.04
13	26-Apr-11	1M	*\$135.00	116.39
14	26-Jul-11	1M	*\$137.00	110.82
15	7-Sep-11	1M	*\$115.00	90.50

Rating/target price changes above reflect Eastern Standard Time

Cummins Inc. (CMI) Ratings and Target Price History Best Ideas Research Relative Call (3 Month)

Analyst: Timothy Thein, CFA
Covered since June 25 2009

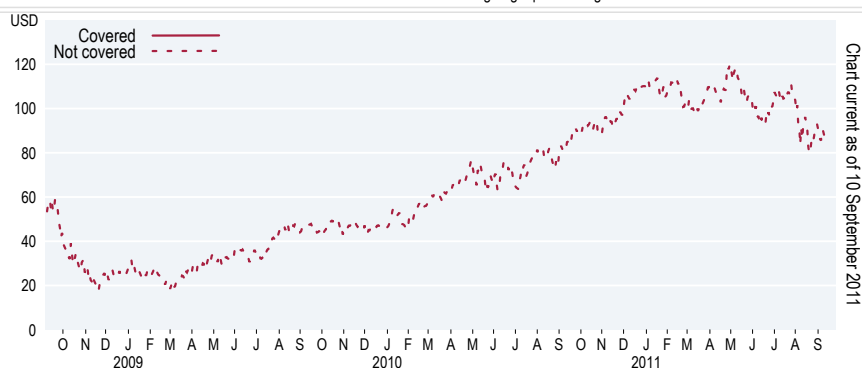


Chart current as of 10 September 2011

* Indicates change

Rating/target price changes above reflect Eastern Standard Time

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Data current as of 30 Jun 2011

12 Month Rating			Relative Rating		
Buy	Hold	Sell	Buy	Hold	Sell

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