Think Corner Research Note

Monitoring U.S./Global Oil and Gas

NATIONAL OIL COMPANY UPSTREAM COST STRUCTURE AND IMPLICATIONS OF LOWER OIL PRICES

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Background

Recently, views on U.S. and global oil production have coalesced around substantial production gains, particularly in the U.S. Implications for customers, energy security, and geopolitics are substantial, mainly for two reasons. First, the prospect of the U.S. being a smaller, rather than larger, import customer in the global oil and gas marketplace could alter political views about strategic interests. Second, the corollary of greater oil abundance is a lower, perhaps considerably lower, oil price deck than the world has experienced the past decade. Opinions for traded Brent tend to range from $65-80 as a possible outcome although some suggestions are $50-60 as an outside possibility. By comparison, conventional wisdom keeps Brent in the $90-110 range; actual prices between 2008 and 2012 have realized short-term spikes exceeding $120 and $140.

Do the shifting views make sense given the prevailing cost structure embedded in the global oil industry? What are the constraints and reality checks? On the optimistic side, what are some "paradigm busters" that could accelerate a re-shaping of the global cost curve? And how would such an eventuality – abundant, lower cost, cheaper oil – sit with the very strong, almost cultural, push away from fossil fuels that has been unfolding over the past decades? A dramatic scale up in liquid hydrocarbon supply supported by an historic reduction in cost and with distinct benefits in lower price and energy affordability would challenge core assumptions ranging from climate to the notions of "peak oil". These are provocative ideas, certainly, and may have some real probability (as yet undefined) of being realized.

Such a major shift in reality and strong departure from established norms would pose direct consequences to a prominent segment of the global oil and gas industry – national oil companies (NOCs). NOCs, either wholly- or partially-owned by their sovereign governments, command the larger share of global oil proved reserves (about two-thirds). They are the gatekeepers to reserves and resources that are converted to production to meet daily global needs. In this research note, we present early results from our updated benchmarking of NOC costs for a limited sample of the best reporting NOCs. ***Our bottom line – an average, weighted breakeven cost of $83-100 per barrel for NOCs in this sample – suggests either substantial adjustments ahead for these organizations and their governments or a reality check on what can be achieved and expected for global oil supply and prices going forward.***

Characteristics of NOC Sample

The sample of NOCs featured in this research note is composed of 11 companies based in nine countries that provide comparable data through high quality public audited financial and operating reports. We maintain and periodically update benchmarks for a larger sample of 49 NOCs from 47 countries.[1] The companies used here are: Petrobras (Brazil); CNOOC, Petrochina, Sinopec (China); Ecopetrol (Colombia); ONGC (India); Petronas (Malaysia); Pemex (Mexico); Statoil (Norway); Rosneft (Russia); PdVSA (Venezuela).[2] Most of the companies in the sample used here have independent audits of their oil and gas reserves and report the results. Seven companies, as indicated in Figure 1, report according to the U.S. Securities and Exchange Commission standards as either their equity and/or debt is publicly traded on U.S. securities exchanges. Although all 11 companies are majority owned by their governments, nine companies have some degree of private ownership.[3] Previous work on the partial privatizations of national oil companies indicates that NOCs subjected to the market discipline and financial and operating transparency imposed by private equity ownership is associated with "comprehensive and sustained improvements in performance and efficiency."[4] In other words, our sample, although small, could represent the "best performers" of the NOC universe.[5]

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[1] CEE has conducted research on NOCs alone and in collaboration with World Bank. See http://www.beg.utexas.edu/energyecon/nocs/ for CEE reports and access to the World Bank site.

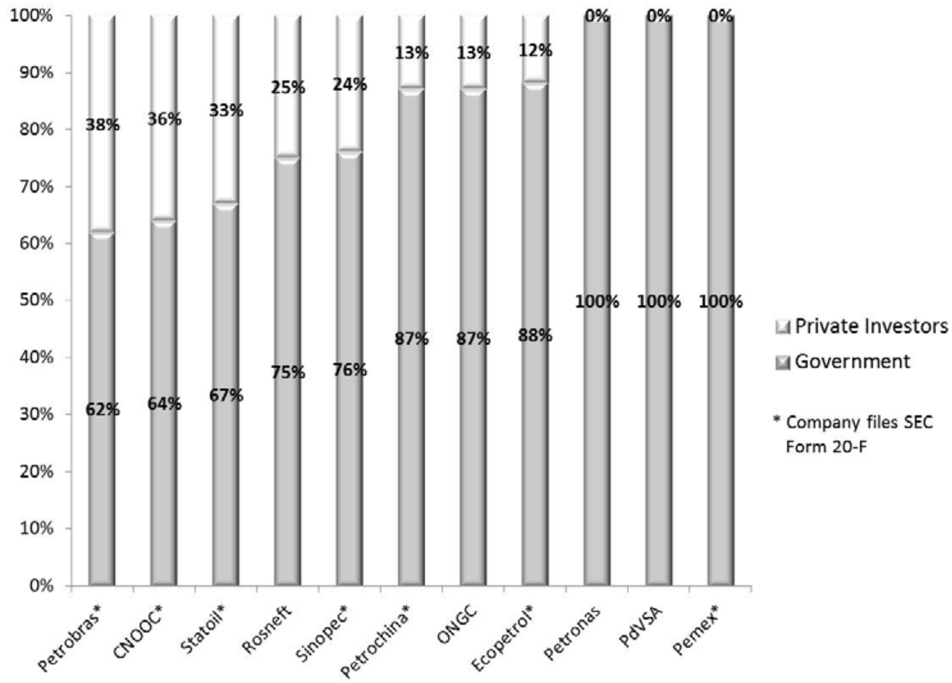
[2] We excluded Gazprom from our sample for analysis: 91 percent of their production is natural gas and E&P EBIT is only 10 percent of total EBIT. In 2011 Gazprom transferred production to their transportation/distribution unit at an average price of $8.79/BOE; they take most of their profits in that unit which is 79 percent of total EBIT. Gazprom is, however, a prominent member of the NOC population with global presence, and like other organizations, such as the Qatar Petroleum subsidiaries (QatarGas and RasGas), heavily dependent upon oil indexation for natural gas sales revenues. We deal with these sensitivities in our closing section and discussion.

[3] Although Petronas is 100 percent government owned, several of its major subsidiaries, including its exploration and production subsidiary, have some private ownership with equity traded on the Malaysia stock exchange.

[4] Wolf, Christian, "Privatising National Oil Companies: Assessing the Impact on Firm Performance", University of Cambridge, Judge Business School. Available at www.iaee.org/en/students/best_papers/wolf1.pdf. Wainberg and Foss, 2006-2007, Commercial Frameworks for National Oil Companies, at http://www.beg.utexas.edu/energyecon/nocs/CEE%20National_Oil_Company_Mar%2007.pdf.

[5] Unfortunately our sample does not include the NOCs from the major producing countries in the Middle East and Africa as they do not report comparable data.

Figure 1. Equity Ownership of Sample NOCs



**Company files SEC Form 20F.*

Even more than equity ownership, many NOCs have entered the debt markets, as shown below in Figure 2.

Figure 2. Debt / Equity (percent)

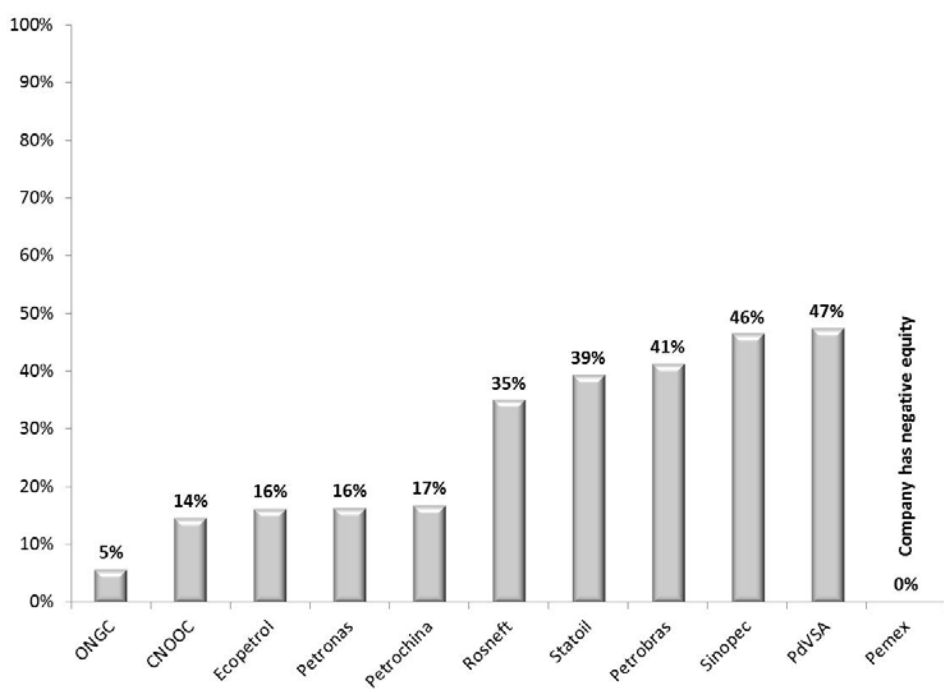
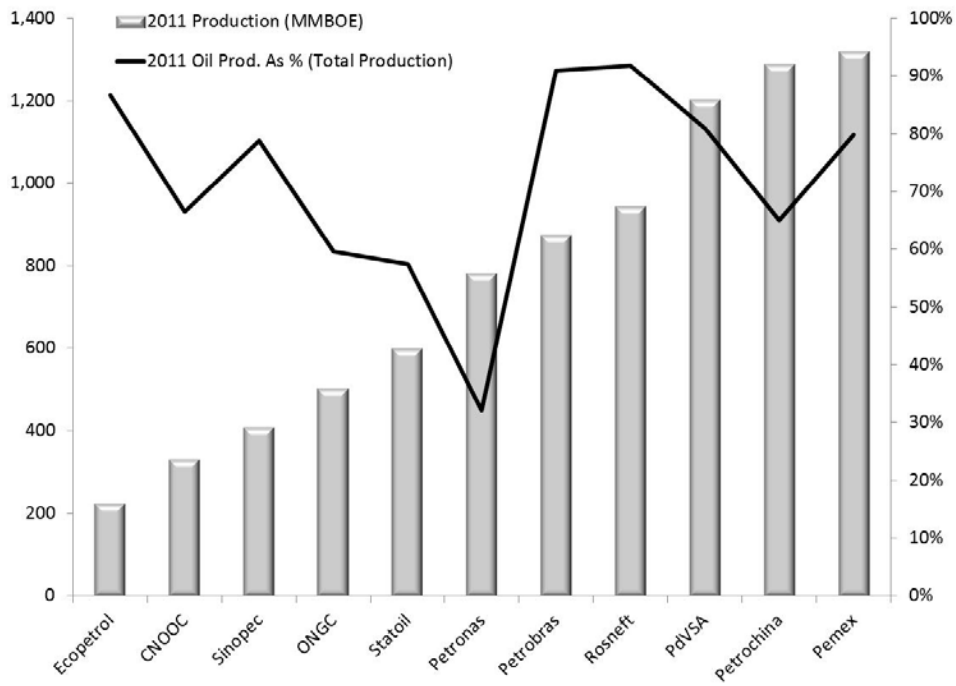


Figure 3 shows that 73 percent of our sample's 2011 production was crude oil. With the exception of Petronas, the majority of each company's production was crude oil. The sample's crude oil production of about 6.1 billion barrels represented 20 percent of total world crude oil production in 2011 of roughly 31 billion barrels (note that we exclude natural gas). By comparison, 2011 production for the Organization of Petroleum Exporting Countries (OPEC) of about 13 billion barrels constituted roughly 43 percent of world output.

Figure 3. 2011 Production (MMBOE)



Upstream Breakeven Cost Methodology

In other work on U.S. producer cost benchmarking, we demonstrated the importance of understanding full cycle, all source, average, breakeven finding and development costs that incorporate both capital and cash costs to derive a more complete and realistic picture of operating company and industry cost structure.[6] Most often, attention is focused on costs to deliver incremental barrels of supply from given locations. Such "supply stacks" yield cost curves (sometimes on a marginal cost basis, but more often using average costs) that indicate how much supply can be delivered relative to demand and price and the tranches of ever more expensive supply that would have to be delivered to balance the market. An example of such a supply stack using countries is shown later in Figure 16. Grainier (usually proprietary) supply stacks compare major plays or producing basins worldwide and their associated costs.

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[6] See Foss and Wainberg, June 2012, "Monitoring U.S. and Global Oil & Gas: Upstream Attainment, Producer Challenges", http://www.beg.utexas.edu/energyecon/thinkcorner/Think%20Corner%20-%20Producers.pdf.

Generally speaking, our concern is that emphasis on supply stacks and basin or play cost structures – important for screening well and play economics – excludes important cost components that can impact producer performance and that can affect decision making and industry responsiveness in important ways. For instance, domestic and international oil companies operating in the U.S. must spread lease operating, overhead, marketing, income and non-income (production) tax, interest on debt, and other cash expenses across all barrels or barrel equivalents produced each year. Cash costs together with capital costs to replace production and prove up reserves for future operations represent the total cost burden faced by producers. Producers also hope to earn a return. If a company's and, ultimately, the industry's cost structure exceeds the commodity market price signal for very long, adjustments will take place even though upstream investments and operations entail long term views.

NOCs face similar challenges, if different in how the NOC relates to its government and home country context. For NOCs, the cash cost exposure is largely comprised of obligations to the state that are non-negotiable – such as revenue contributions, labor and local content requirements, product supply targets, non-core and non-commercial commitments, and the like. Domestic and international oil companies that are U.S.-based can choose whether and where to operate in the U.S. They certainly have legal and regulatory obligations associated with business performance and fiduciary responsibilities to shareholders and investors, but have large degrees of freedom in how to discharge their obligations and responsibilities. NOCs, even the most liberalized companies, by and large, do not have those privileges.

We modified and applied our U.S. producer cost benchmark approach to NOCs using the following criteria.

- Costs are calculated on a U.S. dollar per barrel of oil equivalent ($/BOE) basis for worldwide production. Our cost benchmark is composed of three elements as follows.
    - **Finding and Development Costs:** Total capital costs incurred for oil and gas acquisition, exploration and development for 2009-2011 divided by proved reserve additions (net revisions, extensions and discoveries, acquisitions, improved recovery; we exclude divestments) also for 2009-2011. A three year average (or rolling average over time) is more representative than one year because companies invest today for future results and it usually requires more than one year to properly appraise new discoveries and book proved reserves.
    - **Cash Operating Costs:** The cash costs incurred to produce oil and gas reserves in the most recent year (2011) including lease operating expenses, upstream general and administrative expenses as well as the upstream segment's allocated share of total company cash other expenses and net interest expense, divided by total 2011 worldwide oil and gas production on a BOE basis.
    - **Cash Fiscal Contribution to the State:** Includes upstream production taxes as well as the upstream segment's allocated share of total cash income taxes, refined product price subsidies (either reported or estimated by refining segment operating losses), cash dividends paid to

government shareholders, and cash expenses for country social and economic development, all divided by total 2011 worldwide oil and gas production on a BOE basis. The rigidity of NOC cost structures derives from the unlikely situation that these costs can be avoided in a low price environment. This issue has been a source of tension in global oil markets for some time. Oil and gas producing and exporting countries are heavily dependent upon revenues generated by their NOCs. In many countries, NOC revenue contributions are the substantial share of government treasuries. We come to this point again later in discussing results of our benchmark analysis.

- **Cost Allocation Methodology.** In multi-business segment companies we allocate the costs discussed above (outside of direct upstream costs) to the upstream segment based on the upstream segment's percentage of total company earnings before interest and taxes (EBIT). In our sample and with one exception (Rosneft), upstream EBIT accounted for the majority of the company's total EBIT. In the cases where upstream EBIT was more than 100 percent of the company's total EBIT, at least one business segment incurred losses (generally the refining sector due to price subsidies; see later Figure 6).

Breakeven Analysis Results

The sample results are weighted by 2011 production (cash operating costs, cash fiscal contribution to the state) and by 2009-2011 reserve additions (finding and development costs).

Table 1. <u>Sample Upstream Breakeven Costs $/BOE, Percent of Total</u>

Finding and Development Costs	$12.85[7]	20%
Cash Operating Costs	$14.48	23%
Subtotal	***$27.33***	
Fiscal Contribution to State (FSC)	$35.46	55%
Total	***$62.79***	***100%***

When a 10 percent return ($6.40) is added the sample upstream breakeven cost is $70.36/BOE. We discuss later our rationale for including a return. We also suggest that the $70.36/BOE may understate actual capital requirements, and suggest an adjusted total breakeven cost of $81.27/BOE.

Given all these considerations, $70-$81/BOE upstream breakeven cost is probably a reasonable range. The average FCS share of 55 percent of total cost probably underestimates the full obligation for many NOCs that don't provide comparable financial reports. In many countries, namely OPEC members, governments target an official government oil price that incorporates a "political premium". A widely held opinion among top oil market analysts is that the political premium has grown to meet demands for political stabilization. In combination with the metrics we can

[7] This cost is probably a little understated because of Petronas which reports reserve additions of proved and probable and while all other NOCs in our sample report proved only.

develop, our view is that NOC cost structure explains best the prevailing view among some NOCs and OPEC member countries that a “fair” price for oil is $80-$100/barrel.

Below is detailed discussion on our findings.

Finding and Development Costs per BOE

F&D costs per BOE measure a company’s ability to add new oil and gas reserves in a cost effective manner. It is generally assessed over three years to accommodate the timing differences between the periods when the capital is expended and when the new reserves are reported in the financial statements. The ratio consists of the exploration and development capital spent 2009-2011 divided by the proved oil and gas reserves added over the same period. The proved reserves additions include extensions and discoveries, net revisions, and acquisitions; divestitures are excluded. A related measure is the reserve replacement ratio for 2009-2011 which consists of the proved oil and gas reserves added over the period divided by the oil and gas production over the period. According to Moody’s Investors Service performance in these arenas is critical: “To survive a company must reinvest substantial capital consistently and successfully over a long period of time to find new reserves and replace and grow its production.”[8] Otherwise reserves and production will decrease and the company will eventually liquidate.

The importance of reserves replacement for a NOC, as gatekeeper to a country’s resource endowment, can be disputed. Many have raised the argument about relevance of this measure for NOCs. Indeed, even international oil companies (IOCs) have argued that too much emphasis is placed on reserves replacement for short or mid-term performance and too little on other metrics (given the long lead times for investment and proving up reserves, lack of access to resources, and, thus, the difficulty of achieving 100 percent replacement). However, from reserves comes future production. Inability to replace reserves means, ultimately, constraints on future production and thus revenues. Savvier governments understand this reality and provide lighter-handed dictates on how their NOCs operate and invest. Governments that are heavily dependent on current cash flows from their NOCs are too often shortchanging capital investment programs and creating potential supply constraint conditions both for domestic and global customers. In addition, as we point out earlier, NOCs with some portion of equity in traded shares or NOCs that are dependent upon external debt placements must demonstrate to investors that they can survive and thrive and provide the expected returns and value back to their investors. Reserves replacement is, therefore, an ever more important indicator as NOCs become more sophisticated participants in global capital markets.

Our NOC sample replaced **146 percent** of its production 2009-2011 although three companies failed to completely replace their production (Sinopec, Pemex, and Statoil; Figure 4 below).

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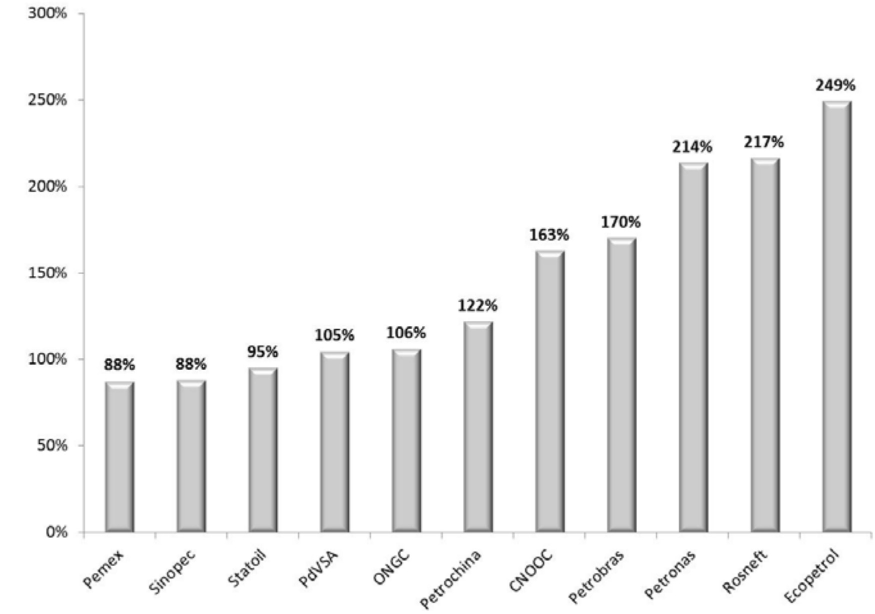
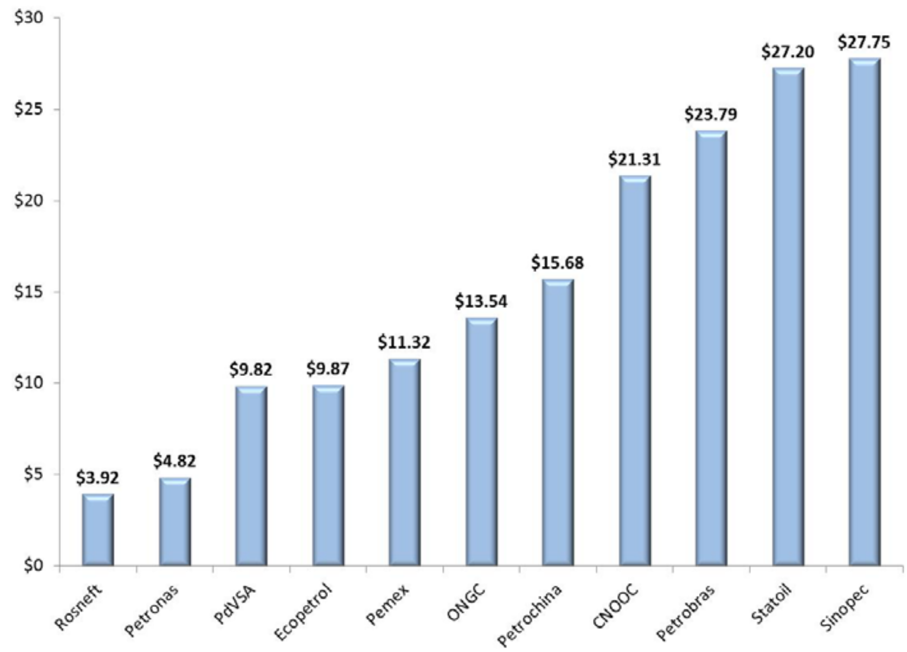
[8] Moody’s Investor Service, *Global Integrated Oil & Gas Industry Rating Methodology*, October, 2005.

Figure 4. 2009-2011 Reserve Replacement Ratio (Percent)



On a weighted average basis, the sample's 2009-2011 finding and development cost was **$12.85/BOE** with a very wide range from Rosneft at $3.92/BOE to Sinopec at $27.75/BOE (Figure 5 below).[9]

Figure 5. 2009-2011 Worldwide Finding & Development Costs ($/BOE)

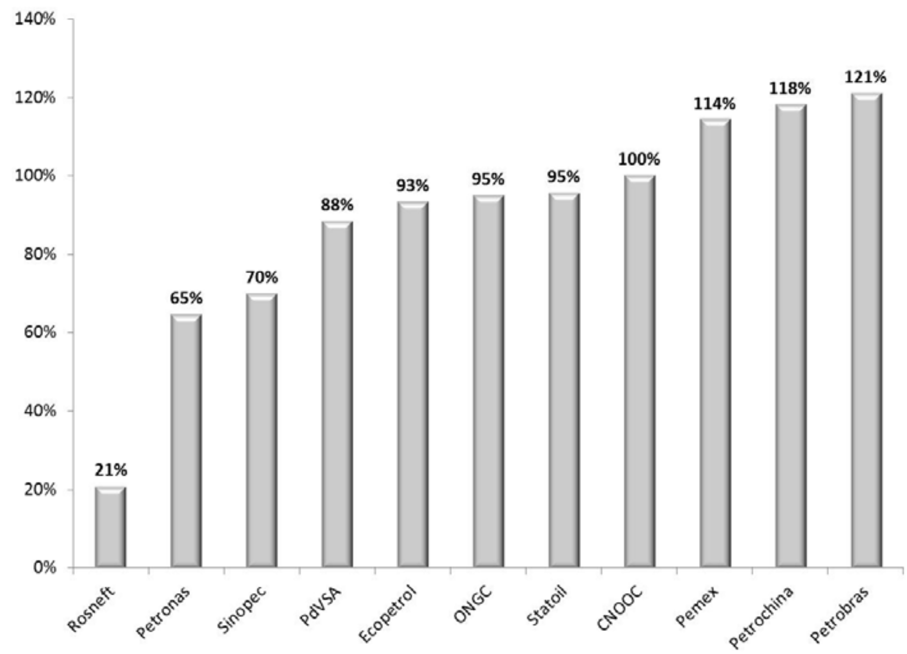


[9] The weighted average finding and development cost per BOE is somewhat understated because of Petronas reserve reporting practices. Petronas reports proved and probable reserve additions whereas all the other companies report proved reserve additions only.

Cash Operating Costs per BOE

This ratio measures the cost efficiency of a company's oil and gas producing operations. To reiterate, cash operating costs per BOE consists of the cash costs expended to produce oil and gas in the most recent year (2011) divided by total 2011 worldwide oil and gas production. Cash costs include lease operating expenses, upstream general and administrative expenses as well as the upstream segment's allocated share of total company cash other expenses and net interest expense. In multi-business segment companies we allocate the costs discussed above (outside of direct upstream costs) to the upstream segment based on the upstream segment's percentage of total company earnings before interest and taxes (EBIT). As noted earlier, in our sample, with one exception (Rosneft)[10], upstream EBIT accounted for the majority of the company's total EBIT. In those cases where upstream EBIT was more than 100 percent of the company's total EBIT, at least one business segment incurred losses, in most cases the refining sector due to price subsidies (Figure 6 below).[11]

Figure 6. 2011 Upstream EBIT as Percentage of Total EBIT



[10] Rosneft is an oil producer (92 percent of production) but 93 percent of their production is sold intersegment at an average price of $27.37/BOE to their marketing and distribution (M&D) segment. Profits are taken in the M&D segment which represented 65 percent of total company EBIT. As a result, only a small part of the allocated costs go to the upstream segment. Rosneft's business model is different from the rest of the companies in our sample.

[11] Petrobras provides a stark example of how even a highly regarded NOC cross-subsidizes other, national content (biofuels, via the company's refining segment, and power generation as Petrobras became the owner of natural gas plants built through private, foreign direct investment).

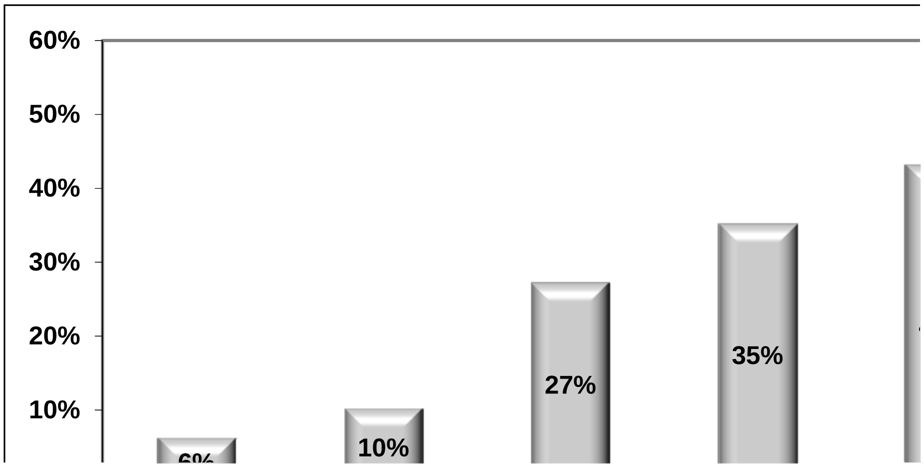
The 2011 weighted average upstream cash operating expenses of our sample was **$14.48/BOE** (Figure 7). The Ecopetrol result of $39.63/BOE is distorted because production taxes are included in production costs and are not disclosed separately. The rest of the companies in our sample disclose production taxes separately and those taxes are included in our metric fiscal contribution to the state rather than in cash operating expenses. As a result, Ecopetrol's cash operating expense per BOE relative to the rest of the sample is overstated and their fiscal contribution to the state per BOE is understated. However, Ecopetrol's total upstream breakeven cost is correct.

Figure 7. 2011 Worldwide Cash Operating Expenses ($/BOE)

2011 Cash Fiscal Contribution to the State per BOE

For our analysis and ongoing benchmarking of NOCs, fiscal contribution to the state is a key determining variable in understanding NOC performance and constraints. As described earlier, this ratio consists of the upstream segments' 2011 payments to their governments in the form of production taxes, cash income taxes, price subsidies for fuel products, dividends paid to government shareholders and cash expenses for country social and economic development divided by 2011 worldwide oil and gas production. Outside of production taxes, the other items are allocated to the upstream segment based on the upstream segments percentage of total company EBIT as in the cash operating expenses calculation. As noted, we expect this component of total upstream costs to be relatively inelastic particularly given the revenue dependency of many governments on their hydrocarbon sectors (Figure 8).

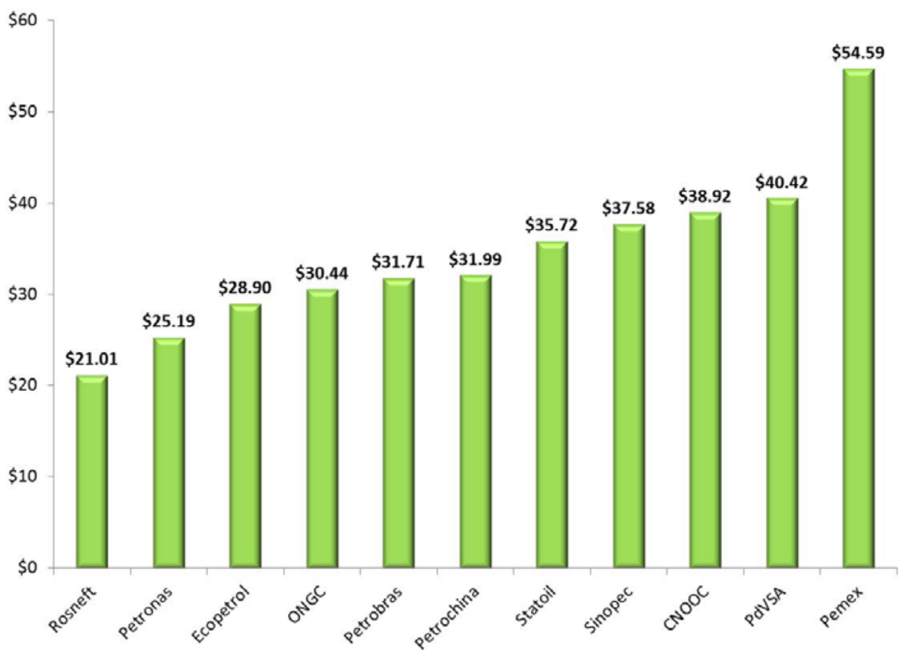
Figure 8. Hydrocarbon Revenues as Percentage of Total Government Revenues 2009[12]



Data for China and India is not available but expected to be insignificant

As shown in Figure 9, our sample's weighted average cash fiscal contribution to the state in 2011 was **$35.46/BOE**, the largest component of the total weighted average upstream breakeven cost.

Figure 9. 2011 Fiscal Contribution to the State ($/BOE)



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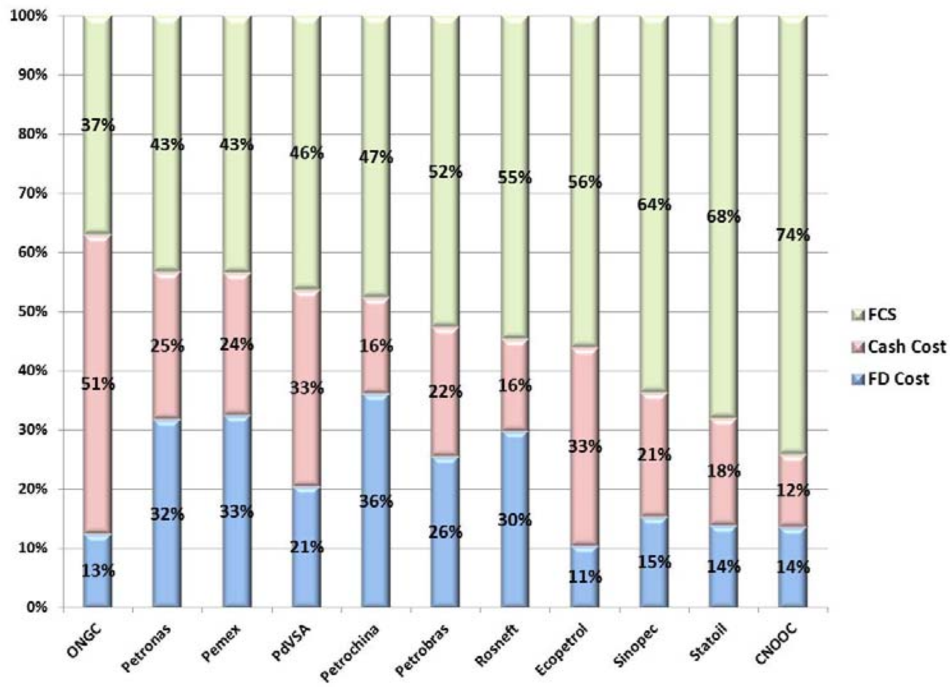
[12] Gulen, G., Wainberg, M. and Foss, M.M. "Value Creation in NOCs," 4th International Workshop on Empirical Methods in Energy Economics, July 13-14, 2011, SMU Cox Maguire Energy Institute, Dallas, Texas, http://www.cox.smu.edu/c/document_library/get_file?p_l_id=749502&folderId=786427&name=DLFE-5049.pdf.

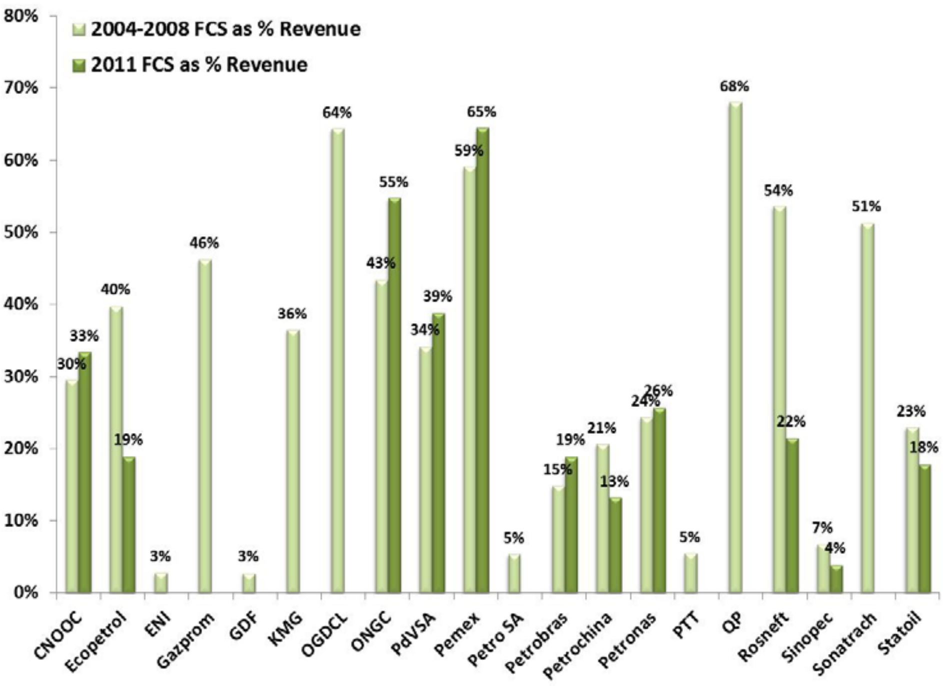
How does the average 55 percent share of government obligations relative to total cost compare for the individual NOCs in our sample? We provide the cost components as shares of total cost in Figure 10 (note again the difference for Ecopetrol in that production taxes, an FCS variable, are incorporated into cash costs as reported by the company). We can look at FCS as a cost item that the NOC cannot control. Many NOCs outside of our sample give up all revenue to their home governments and are assigned budgets for capital expenditures and operations.

Figure 10. FCS as Share of Total Cost (Excluding Return)



How do the results in Figure 9 compare with a larger population of NOCs worldwide? NOC state obligations from our larger sample of NOCs from joint work with the World Bank are shown in Figure 11 below with total fiscal obligations to the state as a percent of total revenue. We include the 2011 update for our current sample (we will be updating the larger population over the next few months). Generally speaking, while still substantial, some NOCs have seen dramatic improvement in their obligations. The main beneficiaries are those in countries and home markets in which the NOC is less heavily relied upon by its government and where the NOC needs to be made more competitive, presumably a necessity recognized by its sovereign overseer. Where NOCs face increased obligations – notably, ONGC, PdVSA, Pemex, and perhaps Petrobras (should Brazil become a net oil exporter) – these happen to be in countries that arguably rely too much on their national companies for socioeconomic development and funding. Again, our main consideration is the NOCs ability to fund its capital program. Pemex remains a stark example of an emerging NOC, a successful entrant into the global capital markets and one that has implemented a high standard in financial and operations reporting, that remains heavily relied upon as the single largest contributor of revenue to Mexico’s government. Information on Middle Eastern and African NOCs remains difficult to obtain. However, given the trends across that region and other analysis, largely proprietary analyst reports, that indicate the close connection between the oil and gas industries and government finances in those countries, our expectation is that the robust obligations for these companies would remain high if not increased.[13]

Figure 11. NOC State Obligations from CEE/World Bank Research



2011 Return on Investment

As noted, most of the NOCs in our sample are in various stages of experimenting with equity (refer to previous Figure 1) and debt issues. Access to global capital – even domestic capital – markets bears many implications not least of which are investor expectations (and transparency in NOC financial reporting to address those expectations). Private investors, which many of these companies now have, demand a return on investment. Presumably, although missions and intentions can be debated, the companies and their governments want returns as well, at least sufficient to fund the companies' capital programs and continue development of their countries' hydrocarbon sectors. We assume a 10 percent return on the sum of finding and development costs, cash operating expenses and cash fiscal contribution to the state which results in a weighted average upstream breakeven cost for our sample of $69.07/BOE (Figures 10 and 11).

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[13] A consistent question we receive is how NOCs and IOCs compare. We will be updating our IOC analysis to estimate an FCS equivalent based on stated obligations – mainly income and non-income taxes – and other disclosed information. Results will be published in a forthcoming research note.

Figure 12. 2011 Worldwide Upstream Breakeven Costs with 10 Percent ROI ($/BOE)

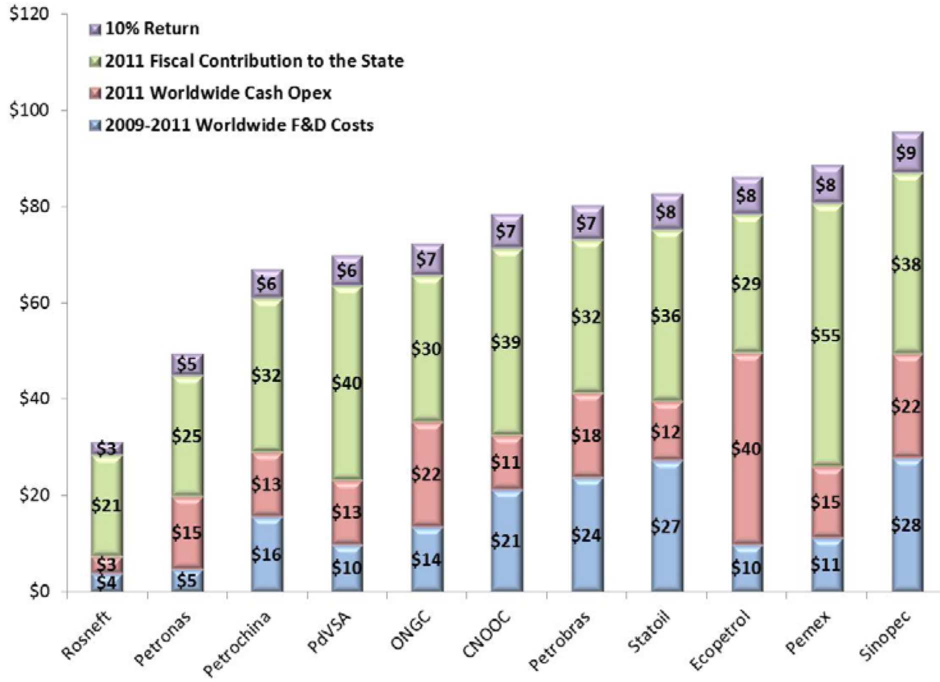
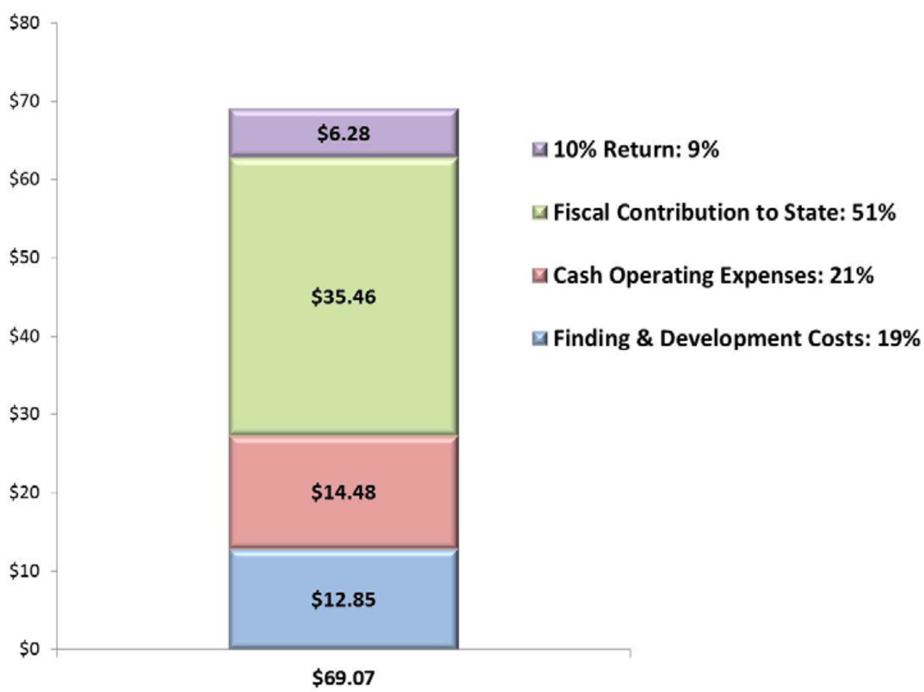


Figure 13. Components of Weighted Average Upstream Breakeven Cost with 10 Percent ROI ($69.07/BOE)

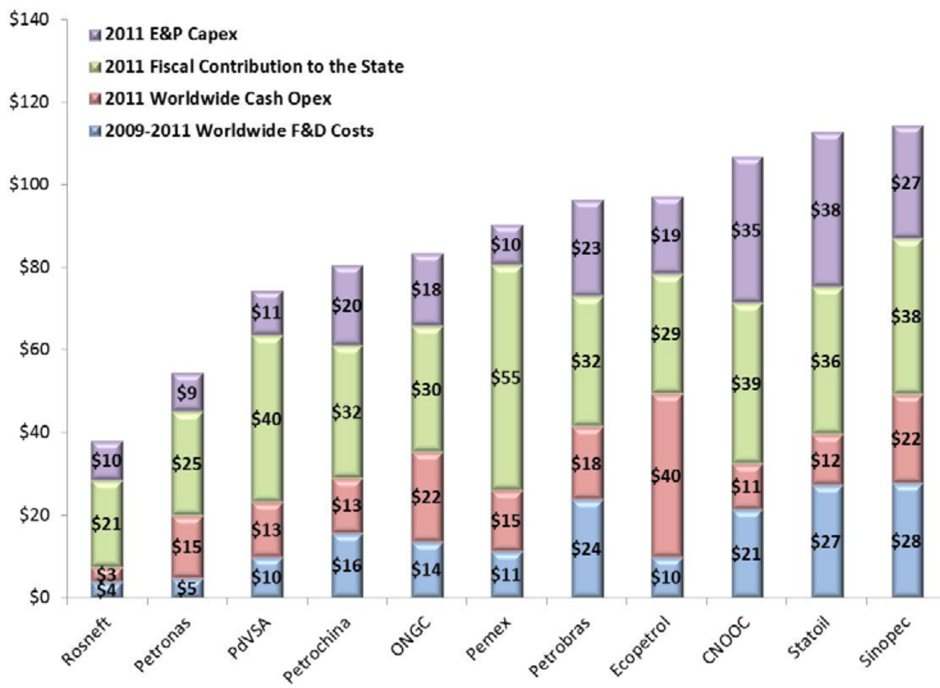


In fact, it may be that the $70.36 breakeven cost is too low. Why? When we compare the dollar amount generated by the 10 percent return for our sample ($53 billion) to 2011 E&P-only capital expenditures of $146 billion, the value of that return only covers only 36 percent of the total E&P capital program for our sample.

If the 10 percent return is replaced by 2011 E&P capital expenditures, the sample upstream breakeven cost is $80.09/BOE. This does not take into account that many companies rely on the upstream segment to help fund their total capital program. In our detailed discussion below, we provide all results, both with and without the 10 percent return, by company.

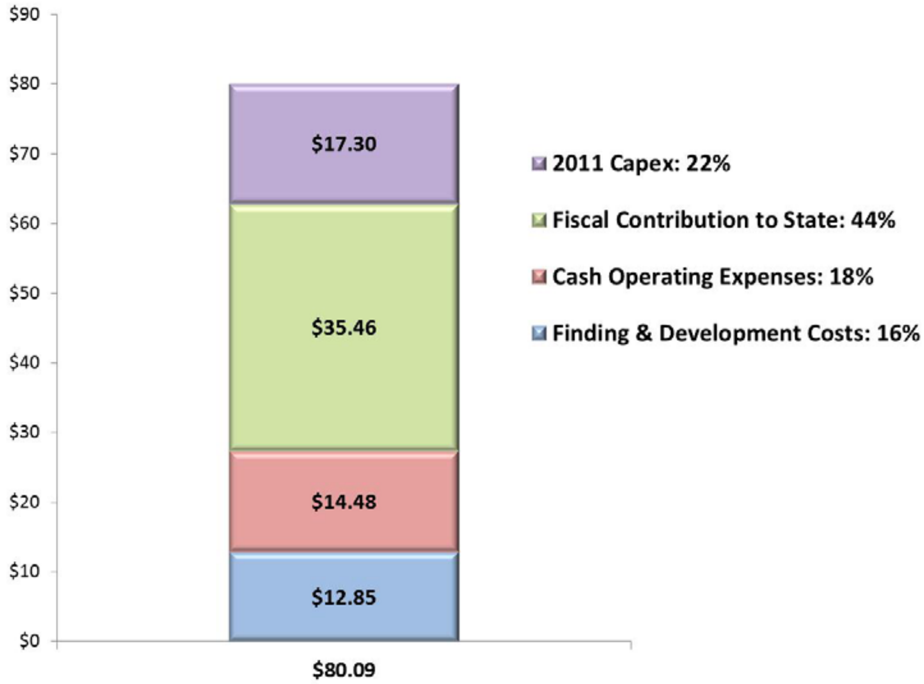
On the other hand, some of these companies may not need to fund their capital programs totally from operating cash flows. Some NOCs (notably CNOOC, Ecopetrol, Petronas, Petrochina and ONGC[14]) have strong balance sheets and can easily incur debt financing. Others are more highly leveraged (Rosneft, Sinopec, Statoil, PdVSA, Petrobras, Pemex) and their ability to incur additional debt may be limited.

Figure 14. 2011 Worldwide Upstream Breakeven Costs with ROI Equal to 2011 Capital Expenditures ($/BOE)



[14] The ONGC debt/equity ratio of five percent appears to be questionable.

Figure 15. Components of Weighted Average Upstream Breakeven Cost with ROI Equal to 2011 Capex ($80.09/BOE)



Oil Price Outlooks and Implications for NOCs in Our Sample

From its historic high of more than $140 in 2008, the Brent crude oil price has traded around the $110 mark, on average, over the past two years. Forward curves in recent weeks pull Brent to near $100 or below in the 2014 time frame. In its 2012 World Energy Outlook released November 12, the International Energy Agency pointed out that fundamentals would keep oil prices higher rather than lower even with robust production growth in the U.S. and other locations and lower demand in the U.S. The agency's price outlook is $125 per barrel in real terms and $215 in nominal dollars by 2035.[15] As we allude in our opening, other projections are for softer oil market conditions ahead. One suggestion is that a lower boundary of $70 for Brent could still support a close to 20 percent expansion in global oil production capacity by 2020.[16] One medium term outlook for Brent pegs an $85 average price by 2017 and suggests a long term band of $72-95 in real terms in which the "$90 floor becomes a $90 ceiling".[17]

Our analysis indicates that a Brent price closer to the lower end of the preferred $80-100 band we point to earlier would introduce substantial stress into the global

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[15] Go to http://www.worldenergyoutlook.org/publications/weo-2012/ for information on the current publication.

[16] Leonardo Maugeri, June 2012, *Oil: The Next Revolution*, Harvard Kennedy School-Belfer Center for Science and International Affairs.

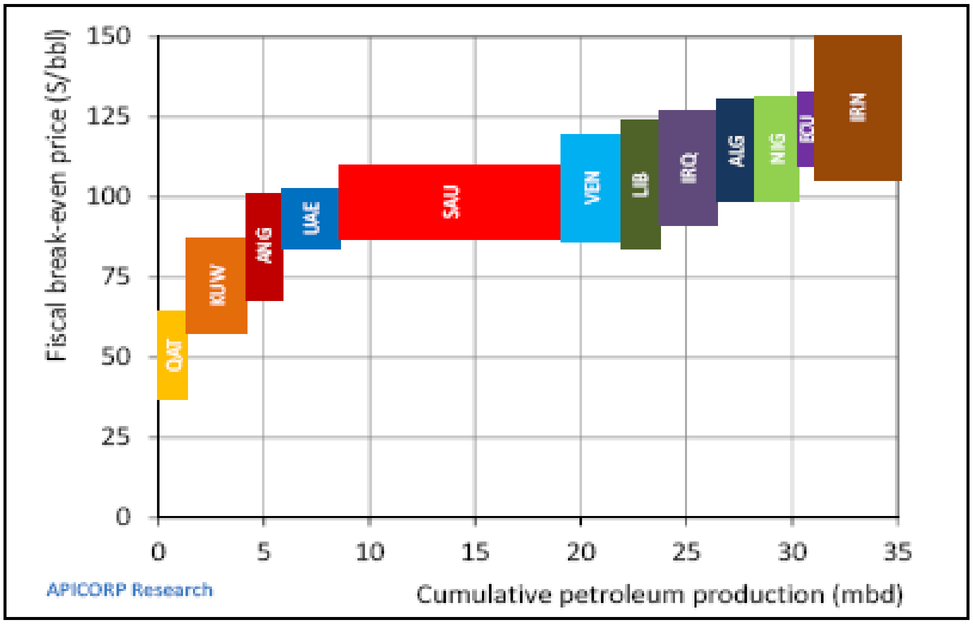
[17] Citi Research, September 2012. Goldman Sachs has Brent drifting down to $85 by 2016.

oil system. The most sensitive NOCs and governments would be those most dependent upon oil export revenues (Qatar Petroleum and its peers in the region); countries that produce only or mainly oil (for instance, Kazakhstan with its 100 percent oil production slate); and NOCs and governments highly dependent upon oil pricing for natural gas sales revenue (Gazprom and Russia, Qatar, Petronas and Malaysia, and so on). The NOCs and governments most likely to be most heavily affected are those that are most opaque, with the African NOCs particularly vulnerable.

The factors underlying potential tensions associated with lower oil prices – which would be of enormous benefit to the global economy and distressed economies like Europe's – are many fold. For all of the attention paid to new sources of reserves and production, especially unconventional plays and deep water locations, these are firmly in the frontier exploration category. These plays remain costly, risky, and bear considerable uncertainty with respect to recovery rates and yields. Many of the most significant new sources of oil production are most prone to public opposition (Canada's oil sands) or security risk (Iraq, where the combination of cost, challenging fiscal terms, and lack of internal institutional capacity to achieve critical targets in supporting infrastructure for oil production growth may result in IOC exits). More interesting is the link between NOCs, government treasuries, and political stabilizations strategies. ***Thus, while many observers are inclined to award geopolitical stability to a more abundantly supplied, cheaper oil price world, it is not clear how the transition in oil dependent economies would fare, especially in view of geopolitical evolution the past two years.***

Our NOC-based analysis of prospective oil price bands is supported by country level analysis of fiscal requirements, i.e., the calculation of "political premium" we referred to earlier. In an article published in the Middle East Economic Survey dated August 13, 2012, Ali Aissaoui calculated the fiscal breakeven oil price ($/Bbl.) for each member country of OPEC (Figure 16). Mr. Aissaoui calculates a weighted average fiscal breakeven price for OPEC of $90-$110/barrel. His analysis is very consistent with the $70-$80/BOE result for our NOC sample, especially if one considers our sample to be the "best performers" among national oil companies.

Figure 16. Fiscal Cost Curve for 2012[18] (Bar width: country's production; Bar heights: price estimate ranges)

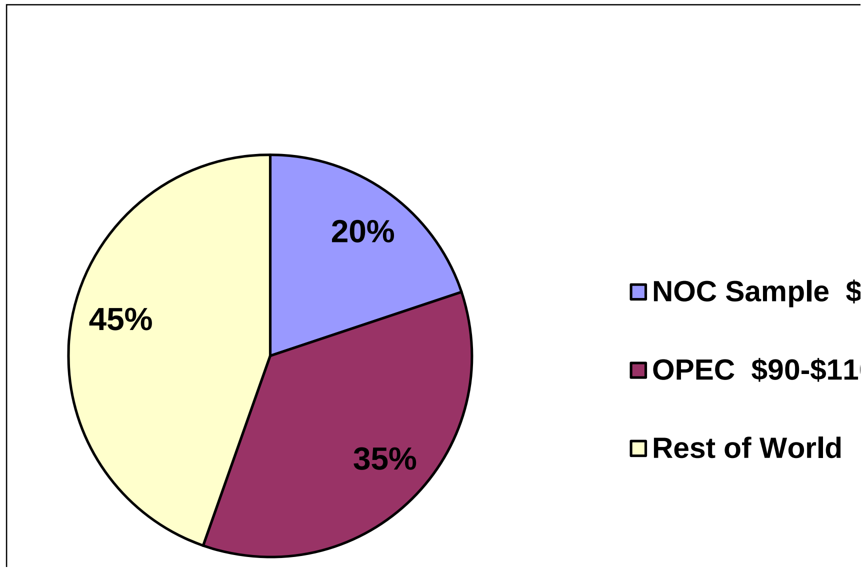


Note: Used with permission.

Our NOC sample and OPEC accounted for 56 percent of total world crude oil production in 2011 (Figure 17) at an average weighted breakeven price of $83-$100/barrel. ***The implication: Prolonged prices at the bottom of or below this range could be financially catastrophic for countries and companies.***

[18] Aissaoui, A., *Fiscal Break-Even Prices Revisited: What More Could They Tell Us About OPEC Policy Intent?*, APICORP Research, Economic Commentary, Volume 7 No.8-9, August-September 2012 and Middle East Economic Survey, August 13, 2012.

Figure 17. Total World Oil Production 2011 (31 Billion Barrels)



Possible Paradigms for a Cheaper Future Oil Market

Having presented the arguments we have, it is important to point to some of the major factors that could create the paradigm shift so many hope for. However, all of the factors we indicate below have significant caveats that must be fully understood and explored in order to build reasonable, testable scenarios.

Factor	Justification	Caveats
Technology advancement	Technology has considerable impact in making tranches of new production sources more affordable as well as reducing risk and uncertainty, including policy and regulatory oversight; unconventional resource plays are a key target for research and development	The long timeline for technology commercialization in the oil and gas industry is well-demonstrated, with 20-30 year time frames being typical for significant market penetration (50 percent market share or more); pace of adoption is influenced by safety, regulatory, intellectual property and many other variables
Liberalized producing government policies	NOCs, IOCs, and oil service companies all face stringent local content requirements that range from indigenous work force targets to local procurement. Many governments impose fiscal terms and contractual constraints that inhibit capital inflows and constrain access to resources by IOCs and often also by indigenous oil and gas companies.	Both local content rules and fiscal terms could be favorably impacted by a prolonged period of flat to lower oil prices. However, local content is politically sensitive (even though results and benefits appear to be questionable). Most oil producing countries could benefit from substantial fiscal reform to decentralize and diversify revenue sources, but internal pressures limit policy innovation.
Breakthroughs in oil substitutes	Incremental gains continue to be made in alternative transportation and other technologies that could	Costs and other constraints, such as access to critical raw materials for applications like advanced battery

Factor	Justification	Caveats
	reduce dependence on oil, with natural gas seen as the best new substitute. Natural gas vehicles, conversion of natural gas to liquid substitute (gas-to-liquids or GTL), or natural gas feedstock for hydrogen fuel cell are the most commonly explored approaches. Electric vehicles with renewables and natural gas (transitionally) as power generation sources remain emotionally popular.	designs, continue to present major hurdles. For all of the claims that breakthroughs are near we note that after many decades of R&D most of the preferred alternative technology options remain far from commercial attainment. This includes other technologies such as coal-to-liquids (CTL) and biofuels which, in spite of an array of environmental and other disadvantages, have provided some contestability in petroleum product markets.

CEE research over the next year will emphasize some of these factors, such as local content policies and their effects. Finally, we noted at the outset the challenge to environmental mores that lower oil prices and oil supply abundance present. Countering these effects are possibilities for carbon taxes or other policy choices that could keep hydrocarbon fuels expensive in order to reduce demand.