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GOVERNMENT TAKE IN UPSTREAM OIL AND GAS

FRAMING A MORE BALANCED DIALOGUE

By Iván Martén, Philip Whittaker, and Álvaro Martínez de Bourio

FOR MOST OF THE past two decades, the revenues of oil and gas companies worldwide have risen steadily, fueled by growing demand and mostly stable oil prices. Total revenues for the industry rose by more than 750 percent to $3 trillion in 2013. Since mid-2014, however, the decline of crude oil prices has hit the industry hard. Revenues have fallen by 36 percent, and companies have aggressively cut costs. For 2015, capital spending for exploration and production (E&P) is expected to have fallen by 22 percent from 2014 levels and exploration investments are anticipated to have declined by more than 25 percent.

One cost, however, has not been possible for companies to cut: the "government take," or the share of oil and gas revenues that governments capture. The government take is distinct from retail fuel taxes, which include excise and value-added taxes and which are subsidized in some countries.[1] The percentage of government take of upstream revenues is particularly critical because it defines a country's competitiveness for internationally mobile exploration and development capital and it shapes global oil prices. If a country's take is too onerous, companies will choose to explore elsewhere, leaving potentially lucrative reserves untapped. The percentage of government take becomes even more relevant as oil prices fall and companies cut capital spending, because countries find themselves competing to attract a shrinking pool of capital.

The government take is extracted through a fiscal regime that details the types of payments companies must make (such as royalties, corporate income taxes, service fees, and profit sharing) as well as the mix and amount. These payments are typically in addition to other requirements, such as agreeing to abide by local-content rules and making R&D commitments.

The government take is by far the largest cost for E&P companies. As high and stable prices increased the potential value of reserves during much of the past decade and a half, governments raised their take. From 2000 through 2014, governments boosted

their share from $9.90 per barrel of oil equivalent (BOE) to $30.40, an increase of $20.50 per BOE. The government take averaged 52 percent of revenues from 2009 through 2014 and reached more than 80 percent in countries such as Algeria and Indonesia. (See Exhibit 1.) Offshore operators bear a marginally higher burden, despite their typically higher cost base. The government take accounted for almost $30 per BOE of offshore costs in 2014, compared with $29 per BOE of onshore costs.[2] Although these increases were not disproportionate given the rise in oil prices during that period, they have become a major challenge in an environment of lower prices.

At Odds with Market Changes

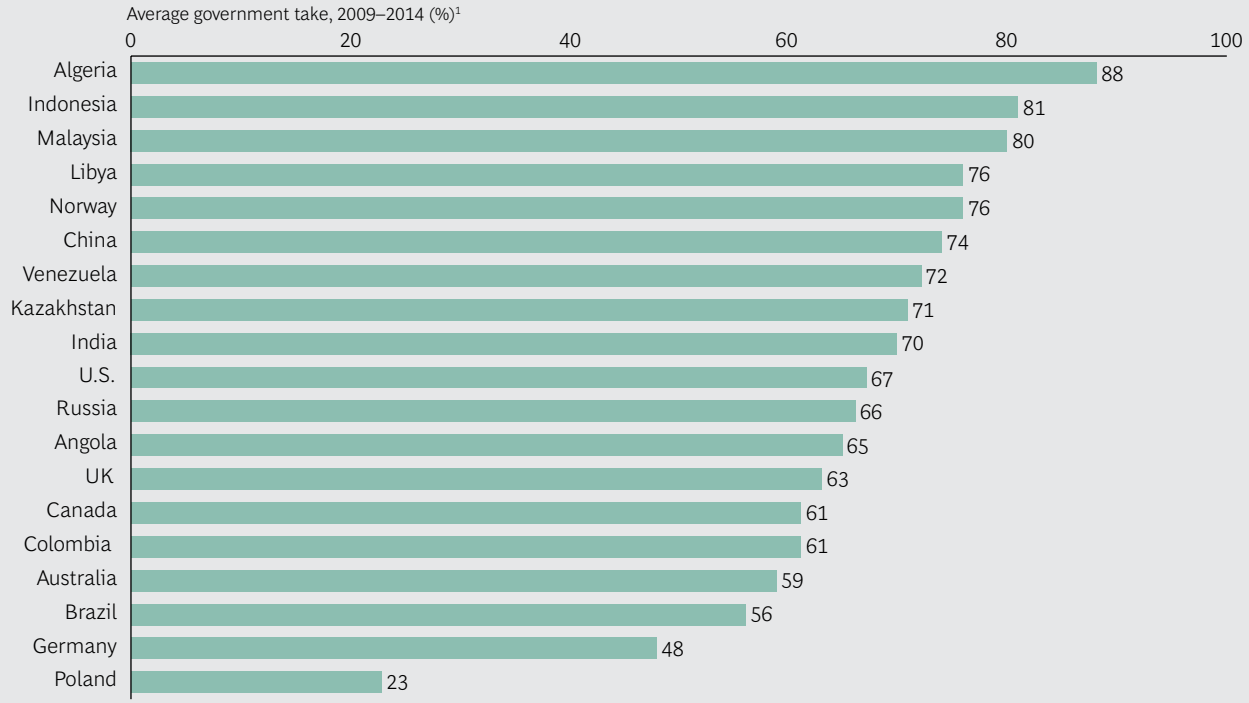
Governments increased their take from 2000 through 2014 for several reasons—rising prices being one, as noted earlier. In addition, some countries realized that the existing financial terms they had established for producers when oil was $20 a barrel were poorly suited for a world in which the price was closer to $100 per barrel. Governments also noticed intensifying competition among companies looking to invest in their country's oil and gas sectors and took that as a signal to tighten the financial terms.

At the same time, many governments introduced more stringent operating requirements, such as tougher local-content rules and aggressive in-country R&D demands.

These operating requirements were well-intentioned: they were part of ambitious nationalization programs designed to encourage national development of energy resources and promote employment. However, these changes increased companies' costs and created market inefficiencies, and today, they are at odds with the market. (See "Killing the Complexity Monster in E&P: Eight Critical Actions for Upstream Oil and Gas Companies," BCG article, January 2015.)

Some fiscal terms are tied to rising and falling oil prices, in which case declines in the

Exhibit 1 | Globally, the Government Take Varies Widely



Sources: Rystad Energy; BCG analysis.
[1]The average government take for each country is the net present value (NPV) of the government take divided by the sum of the NPV of free cash flow and the NPV of government take.

government take occur without any government action. Such declines have already reduced the average lifting costs by about $9 a barrel during the past year. However, further action by governments has been needed, yet their responses to collapsing oil prices have been slower than they were to rising prices. In some ways, the lag in adjusting fiscal regimes to reflect lower market prices is understandable. Governments, after all, want to make sure operators have done all they can to reduce costs before agreeing to collect less revenue.

Yet so far, fiscal responses to the situation have been limited to a few mature basins that are facing the most severe cost pressure. For example, in March of this year, the UK government announced a cut in its Petroleum Revenue Tax from 50 to 35 percent and similarly reduced the supplementary tax charge from 30 to 20 percent, effectively reversing changes that had been introduced in 2011 to increase government revenues in a booming investment climate. With lower oil prices, Her Majesty's Treasury recognized the need for a change. Companies, meanwhile, found many oilfields unprofitable and were considering shutting down production. Despite the fact that the government expects a decline in tax receipts for 2015 and 2016—falling to levels last seen in the early 1970s—it has opted to stimulate the industry rather than protect its share of a shrinking pie. The recent sanction of Maersk Oil's $5 billion Culzean project exemplifies the impact of these changes. These new tax policies boosted the project's internal rate of return by about 5 percent, which led to the company's decision to proceed.

Lower oil prices are not the only reason that governments feel pressure to reduce their take. Countries that are developing their oil and gas resources are using compelling financial terms to lure investment. Mozambique, for example, offered attractive terms to bring in exploration investments, resulting in the discovery of more than 100 trillion cubic feet of gas reserves. The country has since tightened its terms, which could make investment less attractive amid lower oil prices.

Despite these pressures, some governments still see capturing a significant share of oil and gas revenues as a route to shoring up government finances. For example, Russia's finance and economic ministries are debating tax changes that could increase the government's take by more than $20 billion over the next three years.

Finding the Appropriate Level of Government Take

Both governments and oil companies would benefit from a level of government take that is more appropriate for today's market. Fiscal regimes that are out of step with industry revenues constrain oil companies, preventing them from pursuing viable project opportunities. In the longer term, government revenues will fall as a result of these lost opportunities. To prevent this scenario from occurring, governments should adjust their fiscal terms. For example, Brazil has increased its government take for deepwater projects substantially in recent years. Returning it to its historical level of 50 percent could unlock an additional $80 billion to $85 billion in capital in the coming years, according to some analysts' estimates.

Obviously, discussing government take in this new price environment is vital, but in many countries the issue is controversial and therefore politically challenging. In the face of an unprecedented decline in industry revenues, we believe that governments and operators must work together to frame a balanced dialogue so that fair responses on taxation and other forms of government take can be executed. Both sides must show a commitment to the stability and sanctity of existing contracts while accepting trade-offs on objectives, such as improving cash flow, maintaining production levels and value over the long term, and preserving local jobs.

Three Steps to a More Balanced Dialogue

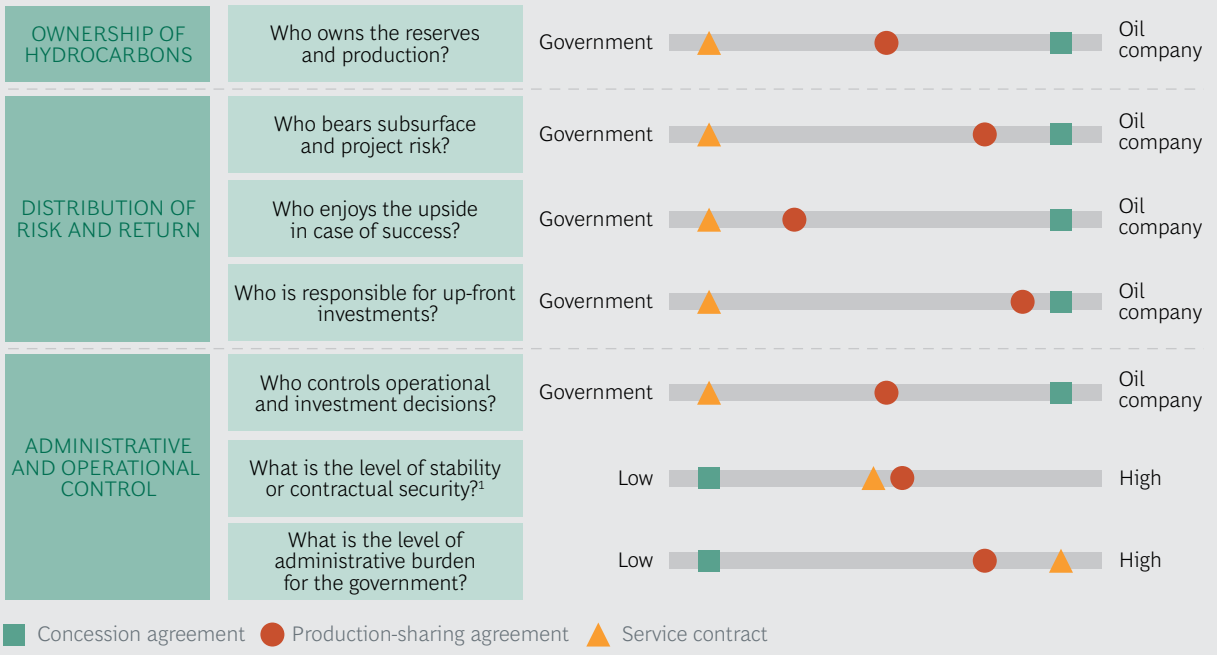
In discussing a government's take, operators and the government must be sensitive to one another's concerns. On the basis of

our experience, both sides should work together and take these three steps in order to have a more balanced dialogue.

Conduct a strategic review of the country's competitiveness related to resource development. In our experience, the government and operators should honestly assess the competitiveness of the country regarding its resources and its current level of take on four dimensions:

- *The Attractiveness of the Country's Resources.* The government and operators should evaluate the attractiveness of the country's resources—particularly the remaining recoverable reserves—and the success of recent exploration investments. An assessment of the resources must reflect not only the subsurface characteristics of the oil and gas fields but also the state of, and plans for, infrastructure and the availability of adjacent opportunities—such as downstream, power, or petrochemical projects—that investors will consider when assessing upstream terms. For example, despite the maturity of lucrative areas such as the Gulf of Mexico and the North Sea, the U.S. and the UK have maintained the attractiveness of these resources through moderate take levels in recent years. This level of take, combined with the areas' dense network of installed infrastructure, has allowed low-cost exploitation of small and marginal oil and gas fields using existing platforms and pipelines.
- *The Current Fiscal Package.* The government must reflect on the types of contracts and the terms it puts in place. The type of contract—be it a concession agreement, a production-sharing agreement (PSA), or service contract—has a fundamental effect on the investment proposition and must be appropriate for the level of opportunity and risk in place. (See Exhibit 2.)
- *The Current Operating Requirements.* Both sides must explore the costs and practicality of the operating requirements. Both also must understand how well current measures are achieving the objectives: are nationalization programs

EXHIBIT 2 | The Contract Type Determines Where the Benefits and Risks Lie



Source: BCG analysis.
[1]Contractual security can vary on the basis of governments' historical willingness to adjust contractual terms.

developing energy resources and promoting employment, and have local-content requirements sparked growth in domestic industry? Too often, the answer to both questions is no. In such cases, the operating requirements should be reviewed.

- *The Country's Perceived Institutional Stability.* Lower political, economic, and reputational risks can make a country's resources more attractive and justify marginally higher government take. But in our experience, this is a secondary factor when assessing competitiveness.

Before responding to this assessment, the government should take two steps. First, study the approaches of other countries competing for direct investment to determine which policies are most suitable for attracting investors. Second, determine how the current fiscal regime compares with that of other countries. We also have found that a government can gain valuable insight into the competitiveness of its approach by sharing experiences and perceptions with oil companies operating outside the country.

Consider adapting the country's fiscal regime if necessary. Being open to changing tax and nontax measures can lead to a more balanced dialogue and, ultimately, to improving the country's competiveness. We have found three areas in which tax packages typically can be adapted:

- *Tax Mechanisms.* The country can adjust its tax or royalty terms by field type or size to compete for investment. For example, to stimulate exploration activities, in 2013 Malaysia lowered taxes on marginal fields with reserves of less than 30 million BOE or 500 billion cubic feet of gas.

- *Tax Regulations.* The government can change tax rules regarding depreciation, losses, and ring-fencing and can also adopt a cost-recovery scheme. For example, Norway allows operators to accumulate losses and use them to offset taxes indefinitely in offshore plays. This creates a huge incentive for operators to reinvest in the event that a project fails, as did Talisman Energy's Yme field redevelopment, which was decommissioned because of structural problems.

- *Tax Refunds and Deferrals.* These measures can be incorporated in the terms and conditions of a contract to incentivize exploration and accelerate payback periods. Norway will give a tax refund of as much as 78 percent of a company's exploration costs in the year it incurs a loss, which has driven relatively intense exploration despite the emerging maturity of the Norwegian continental shelf.

The government also can consider changes to the operating requirements of its fiscal regime to eliminate costs, improve efficiency, and better achieve the originally intended objectives. Programs to develop local industry and promote employment, for example, are often protracted and ineffective, but regular review and adaptation can improve their results.

Be open to adopting an alternative fiscal regime. Finally, the government can facilitate a more balanced dialogue by assessing whether the current fiscal regime creates a competitive investment environment and, if not, changing the regime, including the types of contracts it offers.

Concession agreements that offer ownership of oil reserves have been the most effective way to attract exploration investment, as they hold the potential for large gains. Although Colombia, Norway, the UK, and the U.S. have had success with this approach, concession agreements can expose companies to political and fiscal instability, because governments may decide to adapt the terms of an agreement. Such risk can sow the seeds of uncertainty among oil companies and cause mistrust toward the government.

PSAs can offer a fair return for both parties. Angola's PSAs, for example, have return-rate boundaries that ensure a fair

return for oil companies while avoiding excessive returns in the event that commodity prices increase significantly or reservoir performance is extraordinary. Investors also find the stability of PSAs appealing, given that they are governed by the principles of international commercial contracts.

Service contracts are generally less attractive, because they limit the potential benefits and relegate oil companies to the role of a contractor. These contracts are often employed in situations in which competition for access is fierce. For example, technical service contracts were used in postwar Iraq. However, these contracts often contain meager benefits or insufficient alignment between an oil company and government interests—an issue that is currently driving the adaptation of Iraq's terms.

To pursue a more balanced dialogue, several countries have evolved and tailored their contracts effectively. Brazil uses relatively attractive concession licenses for onshore projects, and it uses PSAs for the exploration of the presalt basins, such as the Santos Basin, and other strategic areas. Angola has pursued a similar approach, using concession agreements for its legacy Cabinda operations and PSAs for more recent deepwater developments. Meanwhile, Iran, as it prepares to welcome international investors, has replaced its 1990s buyback contracts (a short-term service contract) with more attractive "integrated petroleum contracts" that have similar characteristics to other regional PSAs.

Today's Environment Demands Greater Urgency

In the current environment of lower oil prices, governments must work with producers to develop fiscal structures that accommodate the current price environment and address the rising impact of government on the industry. By working cooperatively and with greater urgency than we currently see, governments and operators can shape a more appropriate level of government take that will be mutually beneficial and ensure that oil and gas production will continue to power local economies regardless of crude oil prices.

Notes

1. The tax on fuel has two components: an excise tax, which is a fixed amount for a specific volume (for example, a gallon), and the value-added tax. In developed countries, the combination of these two taxes varies from 20 to 60 percent of the retail price. However, most oil-exporting countries and a few emerging markets, such as China, Indonesia, and Morocco, subsidize retail fuel prices. As a result, the pump prices are lower than the market prices.
2. Prices are based on data from Rystad Energy's UCube database.

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This is the eighth article in a series exploring issues associated with changing oil prices. The previous articles are "Lower, And More Volatile, Oil Prices: What They Mean and How to Respond" (January 2015), "Killing the Complexity Monster in E&P: Eight Critical Actions for Upstream Oil and Gas Companies" (January 2015), "Low Oil Prices Are Challenging Natural-Gas Markets" (March 2015), "Two Sides of the Coin: The Impact of Low Oil Prices on Downstream Oil" (June 2015), "A Golden Period for Asset-Backed Trading: Time to Reconsider Oil Supply and Marketing" (July 2015), "Brent Crude Oil: A Benchmark in Decline?" (September 2015), and "Asset Abandonment in Upstream Oil: A Growing Threat to the Sector" (December 2015).