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**Maximizing the Value  
of Oil Resources in  
the MENA Region  
*The Critical Role of  
Petroleum Fiscal Systems***



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## EXECUTIVE SUMMARY

*The question of how much oil the world will need to meet demand in the coming years is the subject of considerable debate and uncertainty. There is, however, general consensus about the fact that OPEC's role in supplying world markets will increase as non-OPEC supplies reach their peak, and that much of the required increase in production capacity will come from the countries of the MENA region. The addition of future production capacity, which will involve greater technological difficulty, will require investment of hundreds of billions of dollars.*

Meeting this challenge will require national oil companies (NOCs) and international oil companies (IOCs) to combine their skills, capabilities, and resources in long-term partnerships that recognize and protect the rights and hydrocarbon title concerns of NOCs and host countries, while simultaneously offering IOCs incentives to deploy technology, resources, and investment. A key factor in ensuring that these partnerships endure is the design and implementation of a petroleum fiscal system that reflects the NOC's and host government's aspirations yet allows an IOC to earn a return on investment that is commensurate with its contributions.

There are three primary petroleum fiscal systems currently in use: royalty/tax (concession) systems, production

sharing agreements, and service agreements. These have evolved in recent years to a point where they share common features, and all are represented in the MENA region with varying degrees of success in establishing alignment between the NOC and IOC. As MENA governments and their NOCs consider the challenges they will face in extracting hydrocarbons, they will need to tailor their fiscal systems to bring their goals into alignment with their new and existing partners. The fiscal system needs to protect the host government's interests on resource ownership, balance the rewards of the investment opportunity with the risk taken by IOCs, and ensure that IOC partners are incentivized to collaborate with NOCs in maximizing the long-term value of their hydrocarbon resources.

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## SUSTAINING AND ADDING PRODUCTION CAPACITY

With oil prices once again having breached US\$100 per barrel, the debate over future oil supply and demand balances is growing ever more intense. On one side are warnings of an oil price spike by 2015, and on the other a belief that the markets are currently, and will remain, well supplied. Amidst a wealth of analysis, both sides agree on one thing: OPEC's role in supplying world oil markets will increase as non-OPEC oil supplies peak in coming years.

Over the past decade, growth in non-OPEC oil production has been largely driven by the countries of the former Soviet Union. In contrast, many established non-OPEC oil producers have experienced significant production declines. With production

from existing fields declining by an average of about 5 percent each year, the International Energy Agency (IEA) expects non-OPEC oil supply to peak around the middle of the coming decade. Consequently, the agency predicts that OPEC's contribution to global oil markets will rise from 42 percent in 2011 to 52 percent in 2035—a level not seen since the early 1970s.

To meet this increasing demand, OPEC countries continue to invest heavily in new oil production capacity. OPEC-11 spare capacity—defined as the volume of oil that can be brought onstream within 30 days and sustained for a minimum of 90 days—is currently estimated to be just below 6 million barrels per day, and is highly concentrated in the

MENA region, particularly Saudi Arabia (see Exhibit 1). Senior OPEC officials have recently described this spare capacity as a “unique and free service that OPEC members extend to the world community.”

With the world economy emerging from a punishing recession, estimates for oil demand growth—and the amount of related investment

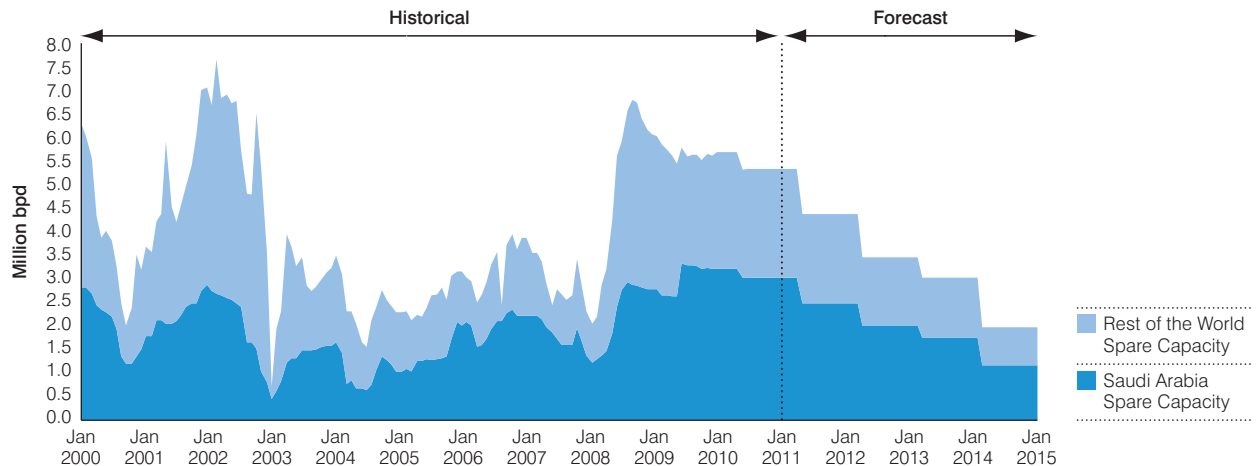
required—remain hugely uncertain. OPEC estimates new oil production capacity investments will range between \$180 billion and \$430 billion between now and 2020, depending upon the growth outlook for the global economy.<sup>1</sup> Even so, the recovery in oil demand that began in 2010 means spare capacity is increasingly being used. Industry analysts<sup>2</sup> predict that spare capacity

will tighten to about 2 million barrels per day between 2013 and 2015—a level comparable to the 2006–2008 period, when oil prices spiked from \$30 per barrel to \$145 per barrel.

The countries of the MENA region will continue to lead in establishing new oil production capacity. With a trend toward increasingly complex

**Exhibit 1**  
Global Spare Capacity Is Concentrated in Saudi Arabia and Is in Decline

SPARE CAPACITY IN THE GLOBAL OIL PRODUCTION SYSTEM



Source: Bloomberg; Deutsche Bank; Booz & Company analysis

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and challenging developments, the addition of new capacity is likely to place greater demands on NOCs. The expected challenges include:

- *Development of less productive, more complex reservoirs:* As the main producing reservoirs of the established super-giant fields plateau and decline, production increases will depend on more complex, variable reservoirs such as the Thamama G and Habshan reservoirs in the ADCO contract area of the UAE.
- *Development of heavy and sour oils:* The Northern Fields project in Kuwait targets oil with a gravity of less than 20° API, and future capacity expansions in Saudi Arabia will increasingly target

heavier, sour fields such as Zuluf and Safaniya.

- *Development of smaller, less-promising fields:* Plans for future capacity expansions in the ADCO contract area of the UAE, for example, target the development of smaller fields (by GCC standards) not previously considered for development.
- *Improved oil recovery (IOR):* The vast majority of the super-giant fields that form the bulk of current oil production require pressure maintenance in the form of water and/or gas injection; ensuring sufficient water injection capacity will be a major challenge throughout the region—for example, in the development

of fields such as Rumaila, West Qurna, and Majnoon in Iraq.

- *Enhanced oil recovery (EOR):* Implementation of EOR—which is already under way by Petroleum Development Oman (PDO) and evaluated by Qatar Petroleum—in the complex reservoirs of the MENA region will likely require a significant investment of time and resources to identify the optimal EOR technology for each field.
- *Increased project complexity:* Successful execution of these expansion projects will require best-in-class project management skills, given the often demanding surface conditions, the huge investment required, and the need to integrate with existing operations.

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### A Primer on IOR and EOR Processes

Improved oil recovery (IOR) generally refers to any process or combination of processes that may be applied to increase the cumulative volumes of oil ultimately recovered from a reservoir. IOR includes the drilling of infill and horizontal wells, the use of downhole pumps, and maintenance of pressure within a reservoir through water injection.

Enhanced oil recovery (EOR), a subset of IOR processes, targets the portion of immobile oil that cannot be recovered through other IOR techniques. EOR processes aim to alter the flow of oil within the reservoir, and include:

- thermal processes (e.g., steam injection)
- gas processes (e.g., nitrogen and carbon dioxide injection)
- chemical processes (e.g., solvent injection and polymer flooding)

*Implementation of EOR will likely require a significant investment of time and resources to identify the optimal technology for each field.*

# FISCAL SYSTEMS IN THE MENA REGION

Against this backdrop, OPEC countries and their NOCs are grappling with the dilemma of how to plan capacity additions in the face of market uncertainty and greater technical difficulties. If they are to maximize the value of their hydrocarbon resources, NOCs will increasingly need to align with IOCs. This alignment should be structured around multiple areas, such as:

- Transparent, **joint, long-term planning between the NOCs and IOCs** for the NOCs to better establish future exploration and production challenges, specific technological needs, and capital expenditure requirements, and for IOCs to execute work effectively and efficiently
- Recognition by IOCs of the NOC's **need to build relevant local capabilities** over the long term to address future technological challenges, and willingness on the part of IOCs to proactively facilitate this development and aid technology transfer
- Recognition by the NOCs of the continued **importance of reserves booking** to the valuation of the IOC and identification of ways to achieve that objective

- Establishment of a **stable business environment** that eases procurement, importation, and other necessary processes
- Recognition by the NOC of the need to **provide the right incentives to the IOC** to encourage the application of appropriate technologies and processes to maximize field recoveries and balance potential rewards with the risks of investment
- Acceptance by IOCs of the NOC's **right to control operations** and realize the majority of the partnership's benefits for the host government

The alignment between an NOC and an IOC is formally expressed in the petroleum fiscal system and related contract provisions that organize and govern IOC participation. With the exception of Saudi Arabia, where participation in the upstream oil sector remains the preserve of the state, all other countries of the MENA region have encouraged IOC participation in order to share risk and gain access to the technologies and experience required for increasingly complex developments. However, host governments and NOCs have taken different approaches, which has resulted in widely differing degrees of alignment and success in providing appropriate incentives for investment such that the role of IOCs in maintaining and increasing production capacity differs markedly from country to country.

Petroleum fiscal systems fall under three main categories (*see Exhibit 2*).

Each system has its own distinctive terminology and mechanism for the division of revenues between the host government/NOC and the IOC (*see Exhibit 3*).

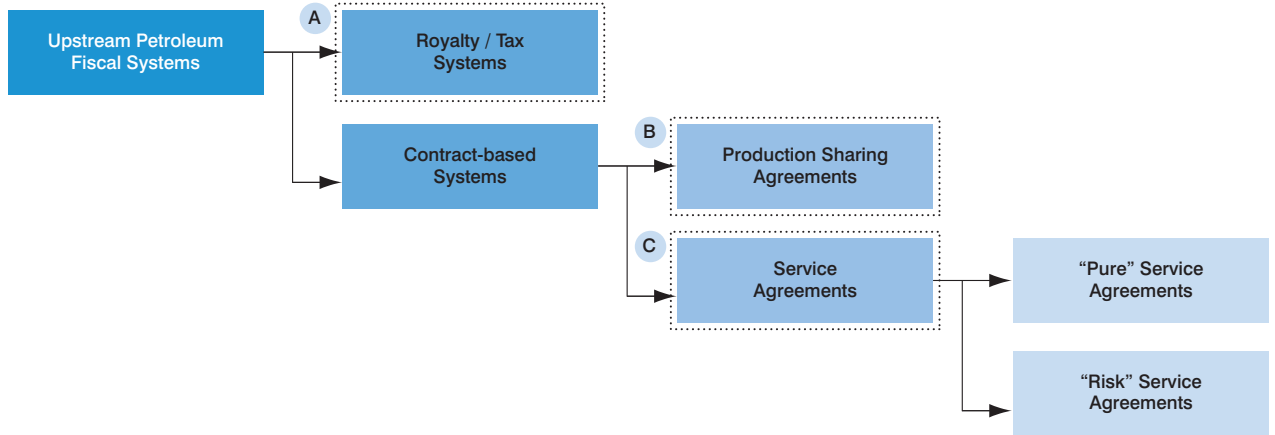
## A. Royalty/Tax (Concession) Systems:

The key feature of the royalty/tax system is that title to produced hydrocarbons transfers to the IOC at the wellhead, which gives the IOC the right to dispose of its equity share of hydrocarbons produced. The IOC is incentivized to invest and maximize production, because it receives the benefit of both volume and price increases and can fully book its equity share of reserves. The host government receives its share of proceeds through a royalty payment—commonly expressed as a percentage of gross revenue from hydrocarbon sales, or a dollar-per-barrel figure—and a tax on corporate profits, allowing for investments and depreciation.

## B. Production Sharing Agreements:

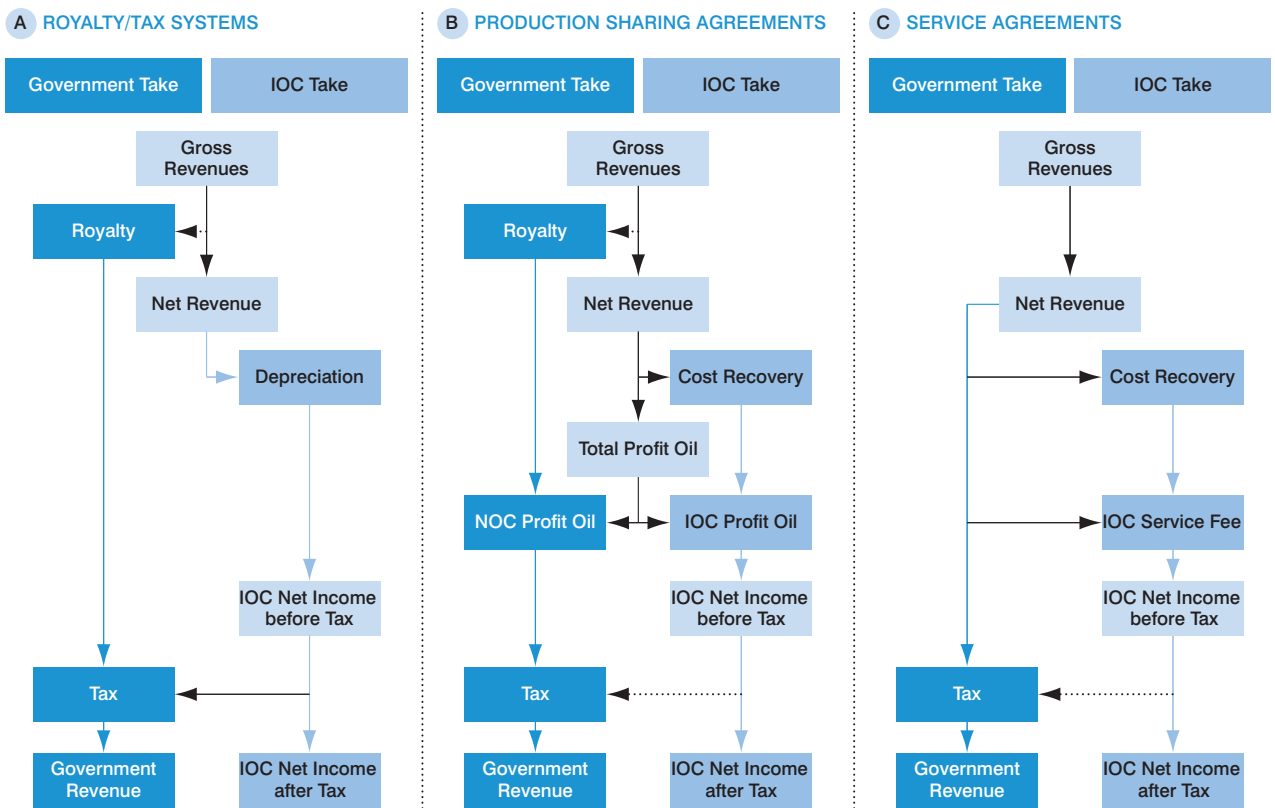
Under a production sharing agreement, an IOC acts as a “contractor”<sup>3</sup> to the NOC; title to hydrocarbons remains with the host government. The IOC typically funds all exploration costs and conducts its operations pursuant to decisions made by an NOC-chaired management committee. Once a discovery is made, the NOC normally funds a predetermined share of development and operating costs. To recover costs incurred during the exploration, development, and production phases, the IOC is entitled to an equivalent amount of oil (“cost oil”). In typical production sharing agreements, the proportion of total revenue that can be used for

**Exhibit 2**  
**Classification of Petroleum Fiscal Systems**



Source: Booz & Company

**Exhibit 3**  
**Key Building Blocks of Petroleum Fiscal Systems**



Source: Booz & Company

cost recovery in any year is capped (the “cost oil ceiling”) to ensure that the host government receives a share of revenue in the early part of the field’s production life cycle. The remaining revenues (“excess cost oil” and “profit oil”) are shared with the IOC in a predetermined proportion that determines the IOC’s return on investment (see *Exhibit 4*). The IOC share of these revenues typically declines as production and project profitability increase.

In contrast to royalty/tax systems, a production sharing agreement allows the IOC to book only the share of reserves that corresponds to its cost oil, excess cost oil, and profit oil shares. Additionally, the NOC is more actively involved in decision making through management committees.

Although IOCs resisted production sharing agreements when they were

first introduced in the 1960s, they have grown increasingly comfortable with them. These agreements generally allow the IOC to share in the upside from increased production, lower costs, or higher product prices (subject to any special rate-of-return features). Additionally, production sharing agreements are accepted in countries perceived to be less stable, in view of the tax stabilization clauses that are often included.

**C. Service Agreements:**

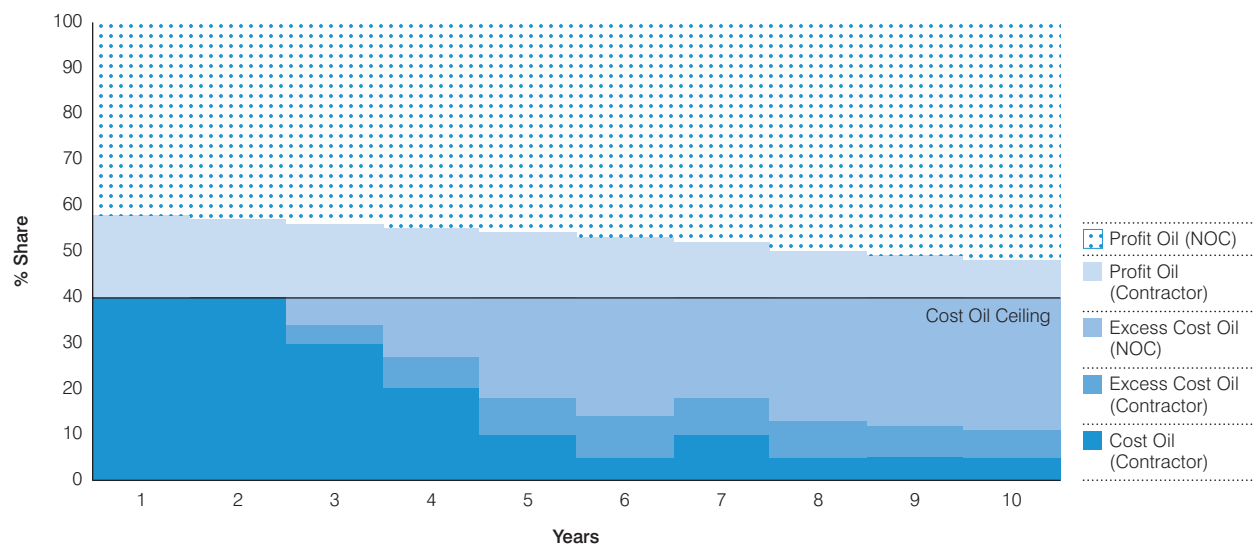
Service agreements come in two main forms. Under a “pure” service agreement, an IOC acts as a contractor to the NOC and receives a predetermined fee for a defined activity. This fee normally compensates the IOC for costs incurred and includes an agreed-upon profit element. IOCs typically have not welcomed such agreements, because the host government retains full ownership

of resources—eliminating the IOC’s ability to book reserves. In addition, some service agreements—such as the “buy-back” agreements used in Iran—specify a return for the IOC based on an agreed cost profile; the IOC consequently bears the entire risk of cost overruns and does not participate in any volume or price upside.

In contrast, a “risk” service agreement—such as the agreements recently concluded in Iraq—establishes a fee on a per-barrel basis, offering the IOC the potential to benefit from any upside and incentivizing it to maximize production. Although the host government retains ownership of the hydrocarbon resources under such arrangements, IOCs investing under the terms of Iraqi service agreements are contemplating booking reserves comparable to the remuneration fee they receive.

**Exhibit 4**  
*The Mechanics of a Typical Production Sharing Agreement Ensure the Rewards Are Shared*

**SCHEMATIC PRODUCTION SHARING AGREEMENT**



Source: Booz & Company

## BLURRING THE LINES

Nearly all petroleum fiscal systems prior to the 1960s were royalty/tax systems; these still predominate in OECD countries today, notably in the U.S., northern Europe, and Australia. However, contract-based

systems are becoming more prevalent as host governments move to protect their resource ownership rights, and countries in the MENA region are no exception (*see Exhibit 5*). Royalty/tax systems form the basis for IOC participation in Morocco and Tunisia, although Tunisia also offers the option of production sharing agreements. Since 2005, royalty/tax systems have also been the basis for license awards in Algeria, which previously offered production sharing systems. In the UAE and Oman, major licenses operate

under royalty/tax principles, but there have been significant modifications to the original systems: For example, in Oman, production sharing agreements are the norm among new awards. Production sharing agreements are now common throughout the MENA region, forming the basis for IOC participation in Libya, Egypt, Yemen, Oman, and Syria. Service agreements are used in Iran, Iraq, and Kuwait. Despite the key philosophical differences between the systems, they increasingly

are becoming more prevalent as host governments move to protect their resource ownership rights, and countries in the MENA region are no exception (*see Exhibit 5*).

*Exhibit 5  
The Three Main Fiscal Systems Are All in Use in the MENA Region*



Source: Booz & Company

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share a number of mechanical, economic, accounting, and financial features that have blurred the distinction between them. Today, individual systems borrow elements from other systems, including such common features as:

*State participation:* Royalty/tax systems in Algeria and the UAE, as is usual for production sharing agreements but uncommon in older royalty/tax systems, provide for active participation by the host government. The PDO concession in Oman is also operated under state direction. Service agreements in Iraq call for a designated

NOC affiliate to be directly involved as a 25 percent state equity partner.

*Bonuses:* Signature and production bonuses are common in all three types of fiscal systems and are often included as a bidding component in licensing rounds.

*Royalty payments:* Production sharing agreements in Syria and Yemen include royalty payments prior to cost recovery.

*Cost recovery:* The cost recovery mechanism common to production sharing agreements is a key feature

of the Iraqi service agreements; the remuneration fee covers cost repayment and a profit element. Similarly, royalty/tax systems compensate IOCs for past investments through tax-deductible cost depreciation over a period of years.

*Profit-sharing:* Modern petroleum fiscal systems of all types include a mechanism that manages the IOC/contractor share of profits. Under royalty/tax systems, corporate income tax payments to the host government increase along with profits. In Algeria, an additional petroleum revenue tax increases in line with the

*IOCs increasingly view production sharing agreements as offering a fair basis for their investment.*

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cumulative value of production to the IOC. This mechanism is akin to a production sharing agreement where the contractor's split of profit oil (and excess cost oil) typically decreases in relation to one or more rate-of-return metrics, such as the rate of production or the ratio of cumulative value to cumulative expenditure.

Iraq employs a similar mechanism in determining the fees payable under its service agreements.

IOCs increasingly view production sharing agreements as offering a fair basis for their investment, as the agreements generally align the goals of the NOC (e.g., resource

ownership, control of operations) with those of the IOC (e.g., access to volume and price upside, reserves booking). In contrast, royalty/tax and service agreements generally do not offer this level of alignment, as the distribution of risks and benefits can be perceived as favoring one of the parties (*see Exhibit 6*).

**Exhibit 6**  
*Benefits and Risks of Petroleum Fiscal Systems from Both Host Government / NOC and IOC Perspectives*

	Contract-based Systems			
	A ROYALTY / TAX SYSTEMS	B PRODUCTION SHARING AGREEMENT	C SERVICE AGREEMENTS	
			"RISK"	"PURE"
<b>Host Government/NOC Position</b>	<ul style="list-style-type: none"> <li>✓ Healthy competition among IOCs</li> <li>✗ Political / social acceptance of title transfer</li> <li>✗ No direct management control</li> <li>✗ Perception of windfall profits</li> </ul>	<ul style="list-style-type: none"> <li>✓ No transfer of title to hydrocarbons</li> <li>✓ Increased control over operations</li> <li>✗ Delayed profit due to up-front IOC cost recovery</li> </ul>	<ul style="list-style-type: none"> <li>✓ No transfer of title to hydrocarbons</li> <li>✓ Increased control over operations</li> <li>✓ Benefit of price upside</li> <li>✗ Limited acceptance by IOCs</li> </ul>	<ul style="list-style-type: none"> <li>✓ No transfer of title to hydrocarbons</li> <li>✓ Full control over operations</li> <li>✓ Benefit of price and volume upside</li> <li>✗ Limited attractiveness to IOCs</li> </ul>
<b>IOC Position</b>	<ul style="list-style-type: none"> <li>✓ Full title to hydrocarbons' booking of reserves</li> <li>✓ Full management control</li> <li>✓ Access to volume and price upsides</li> <li>✗ Exposure to tax changes</li> </ul>	<ul style="list-style-type: none"> <li>✓ Partial booking of reserves</li> <li>✓ Access to volume and price upsides</li> <li>✗ Decreased control of operations</li> </ul>	<ul style="list-style-type: none"> <li>✓ Protection from price downside</li> <li>✗ No booking of reserves</li> <li>✗ No access to price upside, limited access to volume upside</li> <li>✗ Decreased control of operations</li> </ul>	<ul style="list-style-type: none"> <li>✓ Protection from price downside</li> <li>✗ No booking of reserves</li> <li>✗ No access to price and volume upsides</li> <li>✗ Minimal control of operations</li> <li>✗ Full exposure to non-performance risks</li> </ul>

Source: Booz & Company

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## CASE STUDIES: ACHIEVING ALIGNMENT AND ENCOURAGING INVESTMENT

Although IOCs often base their decision to invest, at least in part, on the host country's choice of fiscal system, experience from across the MENA region shows that the detailed design of the individual parameters within a fiscal system is equally important in establishing alignment between the goals of the NOC and IOC.

IOCs are prepared to invest under each of the three main fiscal systems when they are properly incentivized to meet the NOC's goals. Although an NOC may be tempted to push for a larger share of project revenues, a balance must be struck that matches the characteristics of the opportunity with the potential rewards in order to produce a stable, long-term relationship between the NOC and IOC.

Achieving alignment between, on the one hand, the long-term goals of an NOC to maximize the value of its resources and obtain access to leading-edge technologies, and, on the other, the IOC's short-term goal of earning an adequate rate of return is not always easy. These case studies show how the details of the system—when compared to the characteristics of the opportunity—either stimulate or deter alignment and investment.

### **Algerian Royalty/Tax Agreements** The fiscal environment in Algeria

has become increasingly challenging for IOCs since the enactment of the 2005 Hydrocarbon Law, which established royalty/tax agreements as the basis for new exploration awards. Although IOCs normally welcome such agreements because they confer reserves booking rights, the terms of the agreements on offer in Algeria are generally perceived to be out of balance with the risks involved and therefore do not offer the IOC a fair return on investment.

The Algerian royalty/tax system acts like many production sharing agreements in providing the NOC, Sonatrach, the right to back in to any commercial discovery with a minimum 51 percent participation. Royalty rates range from 5 percent to 20 percent, depending on the perceived potential for making a commercial discovery. In addition to a corporate income tax rate of 30 percent, the host government also levies a petroleum revenue tax on the IOC that replicates the “rate-of-return” features commonly found in production sharing agreements. The rate of this additional tax rises from a base of 30 percent to a maximum of 70 percent depending on the cumulative value of production to the IOC.

The resulting harsh fiscal terms in Algeria do not incentivize IOCs to invest in exploration opportunities

in the country. Licensing rounds held since the enactment of the 2005 Hydrocarbon Law have been met with muted industry response—only four licenses were awarded in 2008 and three in 2009. The number of exploration wells drilled by IOCs in the country has dropped from 30 in 2005 to an estimated four in 2010. Given the current low levels of IOC activity, it is doubtful whether Algeria will be able to reverse the declines and restore production levels to their 2007 highs.

#### **Libyan Production Sharing Agreements**

Although initially hailed as a success in attracting IOC investment to Libya, the production sharing agreements established after the removal of sanctions in 2004, known as EPSA IV, are currently perceived as not offering IOCs sufficient incentives for the development of marginal oil discoveries nor the deployment of the technological

solutions required to maximize mature field production.

Bidding rounds held from 2005 onward drew significant industry interest and resulted in the award of exploration acreage to a wide range of IOCs, including Occidental, Chevron, BG, Eni, and ExxonMobil. The main bidding parameter of the licenses awarded under EPSA IV was the percentage of production that an IOC would be prepared to accept to recover costs and receive a profit element. IOCs bid aggressively to secure acreage in light of the high exploration potential they perceived in the country; the average split of production they were willing to accept fell from 19.5 percent in the first bidding round to 13.1 percent in the second round,<sup>4</sup> when competition was at its fiercest. This figure amounted to less than a third of the 40 percent production split more commonly found throughout the region, such as in Egypt.

Because IOCs must recover their costs (which include an obligation to fund 50 percent of development expenditures) from the low production split before they can realize a profit, and because profit decreases as both production and the IOC rate of return increases, EPSA IV contracts are seen as amongst the harshest in the world.

The winning bids were based on the expectation that Libya would yield abundant new material discoveries. But today, five years after the initial licenses were awarded, exploration performance has been disappointing and the discoveries that have been made will mostly struggle to meet minimum economic hurdles for development. Examples include the Hess deepwater Arous al Bahar gas discovery, which may contain 1 to 5 trillion cubic feet but will likely be only marginally economic in view of the 12.4 percent production split that won the bid, and the TPOC onshore

*The discoveries made under EPSA IV terms will have a limited impact on future Libyan oil production.*

discoveries of 10 to 15 million barrels in the Murzuk basin, which are likely to be unprofitable due to a 9.7 percent production split.

It is already clear that the discoveries made under EPSA IV terms will have a limited impact on future Libyan oil production. Production sharing agreements that predated the sanctions have also been converted into EPSA IV agreements at standard terms, typically tied to a 12 percent production split. This has increased the likelihood that more technically challenging IOR and EOR projects will be deferred or dropped because they will no longer be commercially attractive. The low production splits in the new EPSA IV licenses make it unlikely that IOCs will earn enough of a return to help Libya realize its ambition of increasing production from 2 million barrels to 3 million barrels per day.

#### **Iraqi Service Agreements**

In contrast to the examples of Algeria and Libya, Iraq's petroleum licensing rounds in 2009 illustrate that seemingly unattractive fiscal terms may be accepted if the potential rewards

are sufficiently compelling. IOCs' response demonstrated a willingness to accept low-margin service agreements in order to secure participation in some of the largest and most easily accessible development projects awarded in recent years.

Under the terms of the agreements, the contractor IOC is required to fund all capital investment and receives compensation and a share of profits through a remuneration fee. This fee is capped at 50 percent of the revenue generated from incremental production above an agreed baseline, and is only payable once a certain threshold of production above that baseline has been met. As with many production sharing agreements, the fee is adjusted downward once the IOC has recovered its costs and starts to make a profit. The service agreement differs from many production sharing agreements in that the IOC is required to pay a 35 percent corporate income tax.

Despite the harshness of these terms, IOCs are willingly investing in Iraq in order to gain access to its world-scale

development projects and establish long-term cash flow, albeit at very low margins. For the main projects in Iraq,<sup>5</sup> the maximum remuneration possible is capped at \$2 per barrel and can be as low as \$1.15 per barrel. After accounting for the share of the state equity partner, corporate income tax, and the adjustment to the fee once costs have been recovered, contractors will earn less than \$1 per barrel.<sup>6</sup> Despite this low return, contractors expect to earn a 10 percent to 20 percent return on their investment in view of the relative ease by which production can be increased through standard IOR techniques.

There is still considerable debate within the industry as to whether the plateau production rates nominated by the contractors as part of the bidding process can be achieved. However, initial experiences suggest that the Iraqi service contracts have been effective in incentivizing IOCs to rapidly expand production to help meet the host government's objectives, while allowing it to maintain ownership of its resources.

### **Incentivizing Technology Deployment in Oman**

Countries with hydrocarbon resources that are more difficult to access, or in a more mature stage of development, must take into account the technologies they need to attract when considering the appropriate fiscal system and related IOC incentives. Oman is emerging as a leader in the region with respect to IOR and EOR techniques by offering incentives to existing concession holders to develop sophisticated technologies as well as attracting new, technologically competent participants.

Due to its mature production base, Oman experienced a decline in oil production, from 950,000 barrels per day in 2000 to less than 800,000 barrels per day by the middle of the decade, with the decline primarily due to decreasing output from the technically challenging fields in the PDO Block 6 concession area. Deployment of the appropriate EOR technologies to stem this production decline was a central issue during negotiations for the

extension of the concession area in 2004, and led to the establishment of Shell Technology Oman, an EOR research and development center in Muscat. The center is focused on thermal and chemical EOR, as well as providing technical assistance to PDO operations and conducting joint research with local universities. Since 2004, PDO has implemented a number of state-of-the-art EOR projects, including a phased steam injection project to target heavy oil in the Qarn Alam fields, mixed water/polymer flooding to develop bypassed oil in the Marmul field, and a major miscible gas flooding project to increase ultimate recovery in the Harweel cluster.

In addition to including technology deployment as a key criterion in contract negotiations, the Ministry of Oil and Gas has also stimulated investment in fields not core to PDO by creating competition and awarding field rights to new participants. For example, in 2005, the Ministry removed the giant Mukhaiza oil field from PDO oversight and awarded it

to Occidental. Building on its experience managing heavy oil projects in California, the company is conducting an aggressive infill drilling and steam flooding project, involving the drilling of some 2,000 new wells that it expects will increase production from 10,000 barrels per day to 150,000 barrels per day by the end of 2012. In order to stimulate the required \$5 billion in investment, the Ministry decided to operate the field under a production sharing agreement that is quite favorable for Occidental; it reportedly includes a 40 percent cost oil ceiling that allows the IOC to recover costs within a reasonable time frame, along with an acceptable split of the profit.

Through this combination of incentivizing established IOCs to deploy technology and establishing a base of competition by attracting new, technologically focused participants with a fiscal regime that encourages investment, Oman has been able to reverse its recent trend of declining production with oil production once again above 800,000 barrels per day in 2009.

*The Ministry of Oil and Gas has stimulated investment by creating competition and awarding field rights to new participants.*

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## CONCLUSION

OPEC countries of the MENA region will play a pivotal role in meeting future oil demand in the years ahead, even as the technological challenges of extracting resources in these countries increases considerably. Successfully managing these challenges will require deeper collaboration between NOCs and IOCs, founded on a complementary set of goals and targets. It will be critical for MENA governments to tailor their petroleum fiscal systems to adequately align NOC and IOC objectives and ensure that IOCs are incentivized to stimulate technology deployment and investment.

Irrespective of the choice of fiscal system, NOCs should consider following a number of guiding principles in designing and implementing an appropriate fiscal system:

- Ensure that the IOC receives a fair share of the rewards commensurate with the characteristics of the opportunity and the specific technical and non-technical risks the IOC will likely face.
- Provide a stable and predictable system that offers a long-term basis for investment and is able to adapt to unexpected technical challenges and outcomes.

- Establish a basis of competition that ensures the host government will achieve its production and recovery goals while extracting maximum value from its hydrocarbon resources.
- Develop a system that attracts and incentivizes those IOCs that are best able to deploy the required skills and technologies.

Countries in the region that fail to design their fiscal systems appropriately may still attract outside investment, but they risk forming business relationships that are short-lived. The partnerships that persevere will be the ones that are formed through a mutual understanding of what it will take to make both sides prosper. That middle ground will differ from country to country. As the examples illustrate, there is more than one way to achieve a proper balance, but with these principles and lessons in mind, MENA governments will be one step closer to attracting the partners they will need to maximize the value of their natural resources and position the region to meet and capitalize on the world's ever-expanding energy demand.

## Endnotes

<sup>1</sup> OPEC, November 2010.

<sup>2</sup> Deutsche Bank, "Iraq: Oil Development & Implications for the Global Market," December 2010; and Morgan Stanley, "Tightening Supply to Send Prices Higher," November 2010.

<sup>3</sup> Production sharing agreements and service agreements are together referred to as "contract-based systems."

<sup>4</sup> Libyan National Oil Corporation.

<sup>5</sup> Rumaila, West Qurna-1 and -2, Majnoon, Halfaya, and Zubair.

<sup>6</sup> Deutsche Bank, "The Mother of All Oil Stories," October 2010.

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