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Licensing and Upstream Petroleum Fiscal Regimes: Assessing Lebanon's Choices

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Executive Summary

Doubts have been raised and criticisms continue to be made about Lebanon's choice of upstream petroleum fiscal terms and strategies to award oil and gas licenses. This is not surprising given the fact that it is a completely new experience for Lebanon, a country often stuck in stalemates stemming from political disagreements. Despite this, there are some internationally recognized guiding principles that Lebanese policymakers can follow. In terms of the allocation strategy, Lebanon selected competitive bidding, which is a positive step since this method is increasingly popular and supported by the international community. The key concern in Lebanon, however, is the choice of biddable parameters, which should be reviewed further. In terms of block delineation, Lebanon's offshore block sizes do not fall outside the reasonable range, especially when the exploration risk and the relinquishment rule are taken into consideration. With respect to petroleum regulations, Lebanon seems to offer a middle ground between Cyprus and Israel. Some question whether the choice of petroleum fiscal regime Lebanon made is the correct one. In reality, the type of regime is less relevant. Fiscal regimes can be made equivalent in terms of both control and overall economic impact, for given oil and gas prices. The design of the regime, the interactions of different fiscal and quasi fiscal instruments, the details related to the imposition of different instruments, among others, are by far more important. The government should not focus on a specific instrument and instead take into account the net impact on the fiscal regime and the investment climate.

Introduction

Most governments rely on private oil companies for the exploitation of their hydrocarbon resources. Wherever they are carried out, exploration and development activities present delicate legal, technical, financial, and political problems and any solution to these problems requires a balancing act between the respective interests of host governments and investors.

When countries decide to involve international oil companies, they initially face two fundamental decisions: First, how to select the companies that should be awarded the exclusive rights to explore, develop, and produce the resource, known as the allocation strategy; second, deciding what fiscal regime—which includes not only taxes but also instruments such as royalties, bonuses, state participation, and production sharing—should be adopted. No ideal method exists for making either decision. Governments can choose a model that is most suitable for the country's opportunities and conditions from several allocation strategies. They can also select from a spectrum of fiscal instruments when deciding which combination is believed to provide the nation a fair share of the hydrocarbon wealth and encourage investors to ensure optimal economic recovery of the resource.

While an allocation strategy is not as important as fiscal terms with respect to revenue collection, it adds an important dynamic for governments competing for investors' resources (Johnston 2009). As put by Bunter (2002), the award of licenses and contracts is not only about securing an agreement good for both sides in the negotiations in the short term, but it is also about securing an equitable distribution of mutual benefits in the much longer term. Equally important, the process should be demonstrably free of accusations of corruption and partiality.

The design and administration of the fiscal regime will determine how any potential wealth will be shared between the state—the owner of the resource—and the investor, the provider of capital, technology, and expertise. The fiscal regime is also a critical factor in shaping perceptions of an oil and gas basin's competitiveness. Often, however, there is a misunderstanding of what the regime encompasses. The corporate income tax, for instance, is an important component but it is only one of several fiscal and quasi fiscal instruments that together constitute a country's petroleum fiscal regime. Potential investors evaluate the interaction of all these different instruments when assessing the attractiveness of a country. It is also the overall combination of these various instruments that will determine the government's total share of the sector.

The objective of this paper is to assess the choices that Lebanon has opted for in terms of awarding contracts and the upstream petroleum fiscal regime, and compare them to the strategies followed in Cyprus and Israel. As of June 2015, Lebanon has not made any hydrocarbon discoveries yet, although offshore natural gas discoveries in the East Mediterranean indicate a positive outlook.

Due to political disagreements, Lebanon's first offshore licensing round, which was announced in April 2012, has been postponed on several occasions. At the time of publishing, no date has been fixed. The details of the fiscal regime are yet to be published. The analysis carried out in this paper is based on the draft

Model Exploration and Production Agreement (EPA) that was made available to the author in February 2014. The paper also includes comments made by the Lebanese Petroleum Administration (LPA) on the earlier submission of the paper in September 2014, in an attempt to bring it in line with the subsequent revisions made to the EPA since.

The paper proceeds as follows. Section one starts with a brief review of common contract allocation methods based on international experience. The section then analyzes and compares the strategies adopted in Lebanon, Cyprus, and Israel. Section two is dedicated to the upstream petroleum fiscal regime. The section first examines the main types of fiscal arrangements and the key instruments found under each system. It then studies the regime in Lebanon and compares its terms with those of Cyprus and Israel. Section three covers recommendations and concluding remarks.

I Allocation of oil and gas rights

Enhancing oil and gas exploration and exploitation activity is a common goal for all governments. The strategies employed to achieve that goal vary significantly from country to country, starting with the awarding of oil and gas rights (Johnston 2009). Typically, awards are made for the exclusive right to explore and, if certain conditions are satisfied, exploit any commercial discovery.

In order to exploit their hydrocarbon resources efficiently, many governments rely on the involvement of international oil companies (IOCs), often in cooperation with a host country's national oil company (NOC). Governments, however, face a challenging task in deciding which companies should be awarded the exclusive rights to explore, develop, and produce their hydrocarbon resources, and on what conditions such rights should be awarded (Tordo 2009).

The objective of this section is to analyze different allocation strategies and block delineation methods for oil and gas, first as commonly found around the world; second, as they apply in Lebanon, Cyprus, and Israel. The section focuses on countries' actual experience and does not engage in a detailed review of the literature.¹

¹ For a detailed review of allocation strategies, the following references are particularly useful: Milgrom (1989), Fraser (1991), Kretzer (1993a,b), Bunter (2002), Richardson (2004), Cramton (2006) and Tordo (2009).

a Options to allocate oil and gas rights

Countries can assign petroleum exploration and production rights in different ways. Irrespective of the choice, the objective in designing the award process is to find the best candidate, maximize potential revenues resulting from the award, and avoid any distortion of incentives to perform. The allocation strategies are typically grouped under two categories: Open door/informal process and licensing.

The informal process is based on one-on-one negotiations and encompasses two sub-types: 'First-come, first-serve' and direct negotiations. Exploration and production rights are allocated as a result of negotiations between the government and interested investors through a solicited or unsolicited expression of interest.

Licensing entails administrative procedures and auctions. The former is known as a discretionary system that is based primarily on the proposed work program.

Companies present plans for exploration and development according to a formal process. A government committee assesses various proposals against a defined number of criteria. The license is awarded to the plan that has the best 'mix' of those criteria. Under auctions, blocks are awarded on the basis of competitive bids whereby rights go to the highest bidder.

Auctions are becoming the most preferred and adopted process. According to a survey of petroleum agreements made in the early 1980s by publisher Barrows, only twenty-two of the one hundred three petroleum legal systems selected used bidding to award rights for oil exploration and development. Now, at the beginning of the twenty-first century, the majority of countries award petroleum agreements through competitive bidding, which benefits from the competitive instinct between IOCs and has the potential to raise millions of dollars in upfront cash (Duval et al 2009).

The superiority of auctions resides in the fact that, in principle, they are the most transparent way of allocating rights. A central limitation of informal processes, such as negotiation on a first-come-first-serve basis, is that they lack transparency. The criteria for awarding rights are often not pre-defined and known to market participants and the government retains considerable discretionary power and flexibility in awarding exploration and production rights (Tordo 2009). As a result, informal processes are vulnerable to favoritism and corruption, which in turn undermines competition. The reduced competition inherent in an informal process reduces both the efficiency of the assignment and potential revenues (Cramton 2006). As put by Stanley and Mikhaylova (2011, 4) "direct negotiations are engaged in, unfortunately, as a result of corrupt practices." Auctions, however, require rules to be clearly established before the start-up process, offering transparency benefits for both bidders and auctioneers, mitigating potential corruption, and encouraging competition through a fair process (Rodriguez and Suslick 2009).

Compared to auctions, administrative procedures are also less transparent, as it may be difficult for bidders to know the reasons for government selection. In countries that lack a tradition of good governance, administrative procedures are more vulnerable to favoritism and corruption (Tordo 2009). That is why some experts often describe the procedure as a 'beauty contest'. The system also requires a certain level of technical capacity and resources to evaluate the proposals.

One of the main features of the oil and gas industry is the presence of asymmetric information. Private investors undertaking exploration and development are likely to be better informed than host governments on technical and commercial aspects of a project (IMF 2012). This is particularly true in the early stages of sector development when data sharing requirements have yet to be established.

Direct negotiations require detailed knowledge of the prospective profitability of a deposit, which is likely to be unavailable to governments at the time of negotiations. They also require a concentration of administrative effort, negotiating skills, and a detailed assessment of an individual investor's requirements, which in many circumstances may be difficult to achieve. By

contrast, auctions induce investors to reveal their own private information: How valuable the bidders believe the lease to be and which bidder values it most (Rodriguez and Suslick 2009). Competition among potential investors can help offset some of the asymmetry regarding access to information that tends to disadvantage governments in licensing. While problematic in the case of one-on-one bilateral negotiations over contract awards, this informational disadvantage is largely nullified when informed investors are made to compete against each other (Cotula 2010). This is particularly important in underexplored or frontier areas, where information is scarce and the government may not be reasonably confident of the precision of its value estimate (Tordo 2009).

Another key advantage of an auction is the tendency to assign the blocks to those best able to use them. Although this does not always occur, the competitive character of auctions makes it more likely. Companies with the highest estimates of value for the blocks are likely to be willing to bid higher than others, and hence tend to win the blocks (Cramton 2006). Tordo (2009), however, clarifies that the bidder with the most optimistic—not necessarily the most accurate—view of the true value of the block will be awarded exploration rights. Even if all bidders had access to all available data, there would still be a difference in interpretation that would lead to different estimates of the true value of the same block. Each bidder has a view of the risk and expected value of the acreage on offer, and bids accordingly. The winner in an auction tends to be the bidder or consortium that might have overestimated the resource potential and paid more for the area to avoid competitors, consequently suffering the winner's curse.² The risk to the government with overbidding is that the winner may seek a renegotiation of terms. Tordo (2009) therefore argues that an efficient allocation system needs to ensure that blocks are awarded to companies that submit the most appropriate bids, not necessarily the most optimistic ones.

Overall, the popularity of competitive bidding and auctions is likely to continue, especially as many nongovernmental organizations (NGOs) promote their use under the argument that they are the most transparent procedures. The success or failure of an auction, however, largely depends on its design and the government's commitment to transparency.

Informal processes should not be completely dismissed. While direct negotiations may not yield the maximum achievable return to the government, especially if carried out on a 'first-come, first-serve' basis, some countries still engage in direct negotiations, which become inevitable for blocks that were not awarded after a competitive bid round, for instance. As put by Johnston (2009, 30), "there is nothing worse than a failed license round for a host government." Some experts argue that a single allocation policy will likely not apply to all situations in a given country. That is why hydrocarbon laws can make allowances for open-door systems in particular circumstances.

Auctions tend to be the most successful approach once a proven commercial resource has been established. Prior to this, the geological uncertainties can militate against large bids being offered. In fact, the strongest indicator of success of the auction program is the presence of robust competition (Cramton 2006). In any auction model, the government makes substantial gains in net

² Depending on the level of overestimation, the successful bidder may later realize that the terms and conditions of award render the project not economical.

expected values with more competitors, which are further incremented when bidding aggressively (Rodriguez and Suslick 2009). It is therefore always necessary to tailor a design to a particular setting.

Whatever strategy a host government decides to follow, the core requirement is that rights are allocated in a climate of transparency, openness, and the highest standard of professionalism and adherence to international practice (Bunter 2002). Even informal processes can be made transparent through the definition of clear award criteria, publication of negotiation results, and use of external oversight bodies (Tordo 2009).

It is also desirable and increasingly common practice, that, to be able to apply for a license, potential investors should first meet specific minimum criteria—in other words pre-qualify. Pre-qualification safeguards host governments against participants not having the necessary financial and technological expertise to develop the capital intensive oil and gas projects and deal with emergencies such as spills. Non-refundable bidding fees can also be used to discourage participation from companies that are not serious market players, while guarantees may be used to discourage frivolous bids (Tordo 2009).

Since Lebanon opted for competitive bidding, the remainder of this section focuses on this type of allocation of rights.

b Auction design: Two key issues ³

This section addresses two main design elements of an auction: The choice of the biddable parameters and the block size, both of which tend to cause the most controversy.

³ For a detailed analysis of auction design see Bunter (2002), Cramton (2006) and Tordo (2009).

1 Selection of the biddable parameters

A key question host governments face when designing an auction is the selection of the biddable parameters. Once the credentials of potential investors have been established, international good practice favors setting a limited number of clearly specified criteria for the award of a license (maximum two). This is particularly recommended in countries with limited expertise in oil and gas matters and constrained administrative capacity. Even in a country like the US, with more than a century of experience in oil and gas, the legislation forbids the use of more than one bid variable (Tordo 2009).

Typical biddable parameters include the work program and signature bonus. Other biddable parameters can be state participation, local content, and production targets.

The most important biddable parameter is the investor's work commitment, which should be specified in both physical terms and financial expenditure terms.⁴ By ensuring that companies commit themselves, prior to the award of a license, to a minimum work program, the government aims to guard against the possibility that companies, once awarded monopoly rights over the exploitation of the resource, might invest at a level which it considered too small.

Kretzer (1993b), however, warns of the risk of overcapitalization, in that companies propose work programs that are above their optimal level of capital investment, which results in an increased per unit cost of resource extraction.

⁴ For more details, see the Extractive Industry Source Book.

Similarly, Tordo (2009) argues that allocation systems, which induce bidders to offer work programs that exceed what ordinarily would be required to efficiently explore blocks, will ultimately reduce the economic rent and may lead to future renegotiations to remove uneconomic commitments. A key prerequisite for the selection of the work program as the biddable parameter is therefore to have a highly qualified and skilled committee to evaluate the bid, in order to minimize the risk of overcapitalization and ensure the most efficient extraction of the resource.

The signature bonus generates up-front cash, long before any oil or gas production starts. In the US, bonus payments have been an important generator of revenues. From 2005 to 2010 revenue collected by the United States Department of the Interior (DOI) from signature bonuses for the US offshore constituted 27% of total revenue the department collected from offshore oil and gas leases (IHS Cera 2011). In evaluating the potential signature bonus, the investor normally determines the expected profitability of the potential developments and offers a proportion of that value as the signature bonus, which is usually much higher for a discovered oil field than for exploration where the oil potential of the country has not been proven.

The perceived level of competition will also have an impact on the magnitude of the bonus offered. In Angola, competition for one oil block in the country's licensing round in 2005-2006 was so fierce that it resulted in signature bonuses that stunned the industry and ranged between \$902 million and \$1.1 billion, the highest in the world for an exploration block (Brown 2009). Few countries worldwide, however, can extract such a large portion of rent through bonuses. An over-emphasis on collection of signature bonus revenues also has some limitations; money spent on bonuses is money not spent on exploration. In the long run successful exploration and ensuing developments are likely to deliver much greater value for the state than signature bonuses.

In some countries, fiscal instruments, such as the sliding scale royalty and profit sharing, are biddable.

In this case, however, it is recommended that the government pre-set the range within which bids can be placed. Such a prudent approach has several advantages: It allows the government to achieve a greater predictability of potential rewards, which in turn will help with budget planning more generally; it minimizes discrimination among investors and reduces the administrative burden of managing different fiscal structures. Furthermore, there is the danger that companies will offer onerous fiscal terms just to win the bid in the knowledge that the fiscal terms could be renegotiated if subsequent discoveries prove uneconomic. For instance, some companies offer a higher share to the government from profit petroleum when the R-factor—the ratio of cumulative post tax receipts to cumulative expenditures—exceeds a certain limit. However, cost overruns, which are very common in the oil and gas industry, would imply that the higher tier will never be triggered and in some cases may even encourage the investor to spend more than it otherwise would.

In principle, the size of the bid corresponds to the project's anticipated profitability and underlying economics, including the impact of the fiscal regime,

and the level of competition. Oil projects usually attract greater bids than gas projects; given the relatively higher capital and transport costs, the profitability of a gas project tends to be lower than for an oil project of similar size should the same tax provisions apply (Le Leuch 2011). Similarly, the more onerous the fiscal terms, the lower the lease bids and vice versa.

Bids also depend on the extent to which the fiscal regime is perceived to be stable. If investors believe the fiscal terms may tighten, then they are likely to bid much less up front. There is also clear evidence that in times of high prices investors have been willing to contribute a significant amount in signature bonuses (IHS Cera 2011). They are more conservative in periods of low oil prices.

2 Block delineation

Countries can offer a variety of opportunities—onshore and onshore (shallow and deepwater)—with varying risks. There is, however, no specific formula for dividing acreage into blocks.⁵ The choice of the block size should take into consideration several factors—mainly the type of opportunity, the level of competition, the license duration, and the relinquishment provision.

For instance, a high level of competition between prospective investors, an attractive geological potential such as in a proven basin, and/or a lenient relinquishment rule allow the government to offer smaller blocks. By contrast, where interest is very limited, the geological risk is high such as in frontier areas and/or the relinquishment rule is tough from an investor's perspective, larger blocks tend to be offered to mitigate business risk. Johnston (2009), however, warns against the likelihood of a greater accumulation of sunk costs prior to discovery in the case of larger blocks. These costs are typically cost recoverable and/or tax deductible and consequently with larger accumulations of sunk costs, governments risk lower tax revenues.

It is also advisable that host governments not award all their territory for exploration and exploitation simultaneously. Through a gradual award of blocks, the government retains the flexibility to make some changes in the terms and conditions of future awards, following newly acquired information. It is also recommended that governments award licenses to a relatively large number of companies rather than limit the exploration of a large area to a single company, in order to promote competition and allow different interpretations of a territory's geology.

In terms of international practice, typically an exploration license includes three phases, totaling six to nine years, and relinquishment is usually 25% after the first phase and 25% of the original area after the second phase. There is, however, a wide variation.

Relinquishment provisions are imposed to encourage the turnover of the acreage and give the host government greater control over its assets. They are known as 'use-it-or-lose-it' conditions to ensure that exploration activities are carried out by the license holders within a set time frame, or the area is released for future licensing. Relinquishment provisions are important as they avoid 'warehousing', where a company sits on the acreage and delays development until the time best suits them, which is not necessarily the best time for the

⁵ Blocks are defined as rectangular blocks, as specified by a pair of longitude and latitude coordinates (Cramton, 2006).

government (Johnston 2009). Companies can react differently to relinquishment rules; larger players clearly favor smaller relinquishment percentages. In general, a higher relinquishment rate is favored by host governments in unexplored areas as a way to speed up exploration activity.

c Comparative assessment

1 Licensing

Lebanon

Lebanon's offshore oil and gas sector is governed by the Offshore Petroleum Resources Law (OPRL, Law 132 24/8/2010), the Petroleum Activities Regulations (PAR), and the Exploration and Production Agreement (EPA). The first question that arises from this framework is whether a separate law will be developed to cover onshore activities. According to the LPA, an onshore law 'is not yet even discussed.' In most countries, one law applies to both onshore and offshore.

The OPRL refers to awarding licenses through licensing rounds (Article 7) but does not specify the biddable terms. Although Lebanon has not made any discovery yet, the interest that IOCs have expressed in the country and the discoveries made in neighboring countries create a suitable ground for competitive bidding. The Lebanese government further tried to reduce—though not eliminate—the perception of risk in its unexplored waters by preparing comprehensive data packages that were sold to interested companies. Access to information can increase competition especially as risk-averse bidders are induced to bid more aggressively.

Lebanon has adopted a rather prescriptive approach to awarding licenses. For instance, to qualify, applicants should satisfy a set of legal, financial, technical, quality, health, safety, and environment (QHSE) criteria, as shown in Table 1. The pre-qualification criteria that the country selected clearly created a bias toward large oil companies, the rationale being that Lebanon's oil and gas resources lie in deepwater and the larger players have the expertise and capital to exploit them.

⁶ For more details see <http://www.lpa.gov.lb/pdf/Pre-qualification%20Application%20Package.pdf>.

Table 1 Lebanon pre-qualification criteria⁶

	Legal	Financial	Technical	QHSE
Operator	Joint stock company conducting petroleum activities	Total assets of \$10 billion	Operatorship of at least one petroleum development in water depths in excess of 500m	QHSE policy statement(s) Established & implemented QHSEMS
Non-operator	Joint stock company conducting petroleum activities	Total assets of \$500 million	Having an established petroleum production	QHSE policy statement(s) Established & implemented QHSEMS

Source Lebanon Petroleum Administration, 2013

According to the Pre-Qualification Decree (Article 3, s.3), 'the Right Holder may be either one company or a group of companies, at least one of which must prove that it is able to meet the pre-qualification eligibility criteria set forth in the present Decree.'

The provision is in line with the OPRL's definition of a right holder, which can be 'any joint stock company which is participating in Petroleum Activities pursuant to this law through an Exploration and Production Agreement or a Petroleum License that permits it to work in the petroleum sector.'

However, the provision can be subject to misinterpretation and criticism, as even individual companies that do not meet the minimum criteria can still participate, indirectly, in the licensing round.⁷ One possible explanation for such a provision is that the government wants to give local, small companies with no or limited expertise in petroleum operations the chance to enter the sector.

According to the OPRL (Article 1), the EPA is concluded between the state and 'no less than three Right Holders, one of which is the operator.' Lebanon also requires that the operator holds a minimum participating interest of 35% while each non-operator a minimum of 10%. Companies pay a license application fee of \$50,000 (PAR, article 26).

The rationale for the Lebanese government to fix the minimum number of right holders might be to establish a competitive landscape with a variety of players, to control costs and share risks and capital. From a company's perspective, the unincorporated joint venture facilitates risk and capital sharing. From a government's perspective, the structure sets up conflicting interests from which tax authorities can benefit in controlling costs (IMF 2012).

Some would argue that such a provision is not necessary, since in practice, unincorporated joint ventures are a well-established feature of the oil and gas industry structure, particularly in the upstream sector.⁸ Most exploration and production licenses are issued to multiple parties, with a single business designated as the 'operator'.

About fifty-two international oil companies submitted pre-qualification applications and forty-six were short listed. These include major oil companies such as Shell and ExxonMobil, which satisfy the country's relatively strict financial and technical pre-qualification requirements. While such a high level of international interest is surely a positive development, it is also not unusual, especially as oil and gas companies are constantly looking for new opportunities. Furthermore, since the minimum number of right holders should be three, the total number of consortia that can therefore be formed will be smaller than the total number of companies that were pre-qualified.

A difference exists between companies that pre-qualify, those that will actually bid, and the number of contracts awarded at the end; the numbers will shrink as we move toward the latter category. Iraq perhaps best illustrates this case. The country holds the equivalent of 1.9% of world proved gas reserves (BP Statistical Review of World Energy 2014). The fourth licensing round in 2012 focused mainly on onshore gas exploration. About forty-seven companies were originally pre-qualified including oil majors such as BP, Shell, and Total. Twelve blocks were offered. When the terms were revealed, however, only eleven

⁷ See for instance: Nash (2014) 'Lebanon's Murky Petroleum Business', <http://www.executive-magazine.com/business-finance/business/lebanons-murky-petroleum-business>.

⁸ See for instance Ernst & Young (2011) 'Navigating Joint Ventures in the Oil and Gas Industry'.

companies bid on four blocks. Eventually, only three blocks were awarded. Similarly, despite its substantial proved oil and gas potential, Algeria's ninth licensing round in 2011 resulted in only two licenses out of ten on offer being awarded—the tough fiscal terms and the fiscal and political risks were strong disincentives.

Originally, the February 2014 draft of the EPA included the following biddable parameters: The work program, cost recovery ceiling, and profit sharing, the latter being on a sliding scale, related to profitability (R-factor).⁹ The main concerns about having these two key fiscal parameters biddable were explained in Section I.b1 and are further elaborated on in section II.b.

⁹
See Section II. b.

Cyprus

In Cyprus, oil and gas activities are governed by the Hydrocarbons (Prospection, Exploration, and Exploitation) Law of 2007 and the Hydrocarbons (Prospection, Exploration, and Exploitation) Regulations 2007 and 2009.¹⁰

¹⁰
For various documentation please visit: http://www.mcit.gov.cy/mcit/mcit.nsf/dmlhcarbon_en/dmlhcarbon_en?OpenDocument.

Like Lebanon, Cyprus awards licenses through competitive bidding. The island held its first licensing round in 2007 but attracted limited interest. Only three applications for three blocks out of 11 were made by two parties: One to US-based Noble Energy and the other a consortium of Norwegian, United Kingdom, and United Arab Emirates companies (HIS 2007). Originally, a range of international energy companies including Russian, Chinese, United States, Indian, German, French, and Norwegian firms were thought to be considering submitting an offer. Noble Energy, which already had a strong interest in the region, namely Israel, was granted the license in 2008 for exploration Block 12, where Cyprus's first offshore gas discovery, Aphrodite, was later made in 2010. Following appraisal, the field's size had a mean of 5 Trillion Cubic Feet (tcf) of gas (Noble Energy 2013).

The discovery of the Aphrodite field reversed the tide in favor of the government. A second round was launched in 2012 for 12 offshore blocks. Ten consortia (25 companies) and five companies expressed interest. The strong presence of Israeli companies was notable. At the end, five contracts were signed with Italian Eni and South Korea Kogas for Blocks 2, 3, and 9 and with French Total SA for blocks 10 and 11 (BankMed 2014).

Unlike Lebanon, there is no restriction on the minimum number of right holders. In the second round, applications were made by single companies as well as by consortia varying between two and five companies, large and small alike.

Cyprus also offers more relaxed rules in terms of pre-qualification requirements. According to the island's oil and gas regulations, in addition to national security considerations, applicants are selected based on:

- their technical and financial ability
- the ways in which they intend to carry out the activities that are specified in the license
- the financial consideration that they are offering in order to obtain the license
- any lack of efficiency and responsibility that they have shown under any previous license or authorization of any form in any country of the world

The regulations further add that 'if, following evaluation under the above criteria, two or more applications have equal merit, the proposals of the

applicants regarding the protection of public safety, public health, security of transport, protection of the environment, protection of biological resources and of national treasures possessing artistic, historic, or archaeological value, safety of installations and workers and planned management of hydrocarbon resources, shall be taken into account.’

One application is made per block and separate applications can be made by the same applicant for more than one block. Under the latter condition, applicants ‘may mention the priority order they assign to each Block.’

With respect to the biddable parameters, Cyprus is perhaps an extreme example as almost all the fiscal and non-fiscal terms are biddable or negotiable. These include the work program, signature and production bonuses, cost recovery ceiling, profit petroleum, and training fees (as per the Model PSC 2007 and 2012). Such a system makes it difficult to compare the terms of various contracts, discriminates among investors by creating different fiscal structures, and imposes a significant administrative burden on the government.

Israel

Compared to Cyprus and Lebanon, Israel is well ahead in terms of exploiting its oil and gas potential. In 1999, Israel made its first offshore natural gas discovery—the Noa field. Subsequent discoveries (Mari-B field in 2000, Dalit and Tamar in 2009, Leviathan in 2010, and Tanin in 2011) confirmed the presence of significant quantities of natural gas in the Levant Basin (EIA 2013) (table 2). The Tamar discovery was the largest conventional gas discovery in the world in 2009 (Delek Energy 2014a). Production at the field commenced in March 2013. Leviathan, with nearly 22 tcf of contingent natural gas resources, represented the largest deepwater natural gas discovery in the world over the past decade (Noble Energy 2014).¹¹

Israel’s oil and gas sector is governed by the Petroleum Law (5712-1952),¹² applying to both onshore and offshore activities, and the Petroleum Regulations (Principles for Offshore Petroleum Exploration and Production, 5766-2006), in addition to the Natural Gas Sector Law, 5762-2002 (the ‘Gas Law’), which establishes conditions for the development of natural gas, regulates investment in the sector, and ensures the safety of operations.¹³

Petroleum Rights are granted in response to applications submitted from time-to-time.¹⁴ The Petroleum Law also enables the granting of licenses for exploration and leases for production by way of competitive bidding. The latter procedure, however, has not been used yet and no information on the bidding parameters is available.

One explanation could be the relatively limited international interest. The oil majors appear to be hesitant about investing in Israel because they fear endangering their more lucrative investments in Arab countries. The political risk in Israel is also seen as significant. A study done by IHS Cera (2011) carried out a comparison of the political risk in terms of political, socioeconomic, and commercial attributes, across several countries. Israel was ranked poorly at 113 alongside countries including Sudan, Bolivia, Myanmar, and Sierra Leone. As put by IHS (2011, 14) ‘three factors serve as significant external constraints on

11

‘Classification of the contingent resources in the Leviathan Reservoir as reserves is contingent, inter alia, on approval of a plan for the development and commercialization of the natural gas and the condensate from the reservoir and a reasonable forecast for natural gas and/or condensate sales ... There is a reasonable chance that the contingent resources in the best estimate category will be economic’ (Delek Energy, 2014b, p.3).

12

Amended in 1965.

13

Various documentation can be found on the website of Israel Ministry of National Infrastructures, Energy, and Water Resources.

14

The Petroleum Law defines three types of rights for the different stages of exploration and production of petroleum: the Preliminary Permit enables its holder to conduct preliminary investigations; the Petroleum Licence confers on its holder the exclusive right to explore for Petroleum in the licensed area; and the Petroleum Lease is granted to a holder of a Petroleum Licence that made a discovery of Petroleum in commercial quantities - it confers on its holder the exclusive right to explore for and produce Petroleum in the area covered by the Petroleum Lease.

foreign investment. First, the announcement from Israel's National Infrastructure Ministry in July 2000 that it was suspending new licenses and permits to consider what would be tougher terms has had a chilling effect on investors, who were quick to announce they would reconsider further investment in Israel if royalty rates were significantly altered ... that threat has been reiterated as legislation slowly makes its way through government. Second, the threat of a Middle East war involving Israel is omnipresent ... and companies cannot help but account for this in their investment plans. Third, the omnipresent threat of internal violence ... is one that cannot be ignored, even during times of relative peace in the nation.'

Table 2 Natural gas discoveries in the Eastern Mediterranean region

Country	Discovery Year	Name	Size (Tcf)
Cyprus	2011	Afrodite	5
Israel	1999	Noa	0.04
	2000	Mari-B	1.5
	2009	Dalit	0.7
	2009	Tamar	10
	2010	Leviathan	19
	2011	Dolphin	0.08
	2012	Simson	0.55
	2012	Tanin	1.2
	2013	Karish	1.8
	2014	Royee	3.2
Palestinian Territories	2000	Gaza Marine	1

Sources **Delek Energy 2014a&b, EIA 2013, Noble Energy 2014, Israel Opportunity 2014**

Furthermore, following the Tzemach committee recommendations in September 2012, the Israeli cabinet decided to cap gas exports at just 40% of potential reserves in order to guarantee domestic supply for the next twenty-five years. There have also been calls to impose additional taxes on future gas exports. Strong public feeling against exporting gas can act as a disincentive for companies looking for the most economically efficient solution to exploit gas resources.¹⁵

Between 2000 and 2013, Israel's regulatory and fiscal framework for upstream oil and gas has been revised on several occasions, negatively affecting investors' confidence. According to Dor and Danishefsky (2011), in 2000 the then Israeli Ministry of National Infrastructure (which later became the Ministry of Energy and Water Resources) froze all offshore activities in order to allow the government to consider amending the regulations and the fiscal regime. More than six years later, the sector was opened to new exploration. Following the discoveries of Tamar and Leviathan, the Israeli government further introduced restrictive regulations and tightened its fiscal terms.

Like Cyprus, there are no requirements on the number of applicants per

¹⁵ An inter-ministerial committee charged with recommending a national gas policy.

petroleum right, which can be granted to one or more parties. But in a sharp contrast to Cyprus, Israel petroleum regulations are highly prescriptive. For instance, the regulations demand certain minimum experience requirements in offshore exploration and production activities, as a pre-condition to granting petroleum rights covering offshore areas of various water depths:

- For a license in which the water depth does not exceed 100 meters, experience of drilling at least one offshore well
- For a license in an area in which water depth does exceed 100 meters, experience of drilling at least one well at a depth exceeding 100 meters

The regulatory changes made in 2010 imposed for the first time the need to appoint an operator with experience in managing and performing at least one offshore project of \$100 million, within the last five years.¹⁶ They also set the criteria for determining the minimum financial ability of an applicant who must be able to fund at least half of the approved project's expected cost estimated to be \$100 million.

The new set of guidelines which were added in 2011 introduced additional experience requirements for drilling in water depths up to 500 meters, up to 1,000 meters, and above 1,000 meters (as opposed to the single 100 meter threshold under the 2006 regulations). The operator must be a partner in the oil and gas right and hold at least a 5% interest in the license while foreign operators are required to submit a questionnaire on their foreign trade and relations (Dor and Danishefsky 2011).

The regulations limit the maximum size of an offshore right to 400 square kilometers (400,000 Dunams) and no person shall hold more than 12 licenses or hold licenses for an aggregate exceeding area of 4,000 (4 million Dunams) (Deloitte 2014). For instance, the Pelagic Licenses awarded to Israel Opportunity Energy Resources LP, covers five blocks of 400 Km² each, resulting in a total area of 2,000 Km².

Licensees must pay a fee set by the minister of energy and water resources based on various factors such as length of the license, the size of the covered area, and other relevant factors (Hayes 2011).¹⁷ The petroleum license includes a work program to be carried out during the term of the license—typically at least one exploration well for a predefined minimum depth (Hacohen 2014). The merit of each application is assessed per various criteria, mainly experience and financial capacity.

¹⁶ As later specified in the 2011 regulatory changes.

¹⁷ Licences under the 1950s regime were allocated free of charge.

2 License duration and acreage

There are significant variations between license durations and extensions as well as relinquishment rules between the countries assessed.

In the case of Lebanon, the issues of exploration license duration and extension would have benefitted from further clarification, as the existing provisions in the OPRL and Model EPA can lead to different interpretations, especially with respect to the exploration phase and period.

According to the OPRL (Article 21), 'if the Exploration phase, provided by the Exploration and Production Agreement is shorter than ten years, the Council of Ministers may, upon an application submitted to the Minister, and on the basis

of a proposal by the Minister based upon the opinion of the Petroleum Authority, extend the Exploration phase within the ten year time limit.' As such one concludes that the exploration phase is of a maximum of ten years including any potential extension.

The OPRL does not refer to the division of the exploration phase into several periods. The PAR, however, in Article 30, states that the phase 'may be divided into periods of time related to the work plans submitted by the Right Holder in the Exploration and Production Agreement.' Following direct input from the LPA and according to the Model EPA, the exploration phase is divided into two periods: Period 1 (three years) and Period 2 (two years). Only Period 2 can be extended by one year for appraisal, thus the total exploration phase period could be six years. At the end of the Period 1, the right holders relinquish 25% of the block.

The exploration phase can be extended 'for justified operational reasons or Event of Force Majeure, subject to Council of Ministers approval,' as long as the total phase does not exceed ten years. On each extension, a relinquishment rule of 50% would apply. This is the only rate specified in the OPRL. Such a formulation of extensions and relinquishment rules could have been kept much simpler. Greater consistency between the law, regulations, and model EPA is recommended.

As shown in table 3, compared to Cyprus and Israel, Lebanon offers the shortest duration of the exploration phase (five years compared to seven in Cyprus and Israel, excluding the possible extension for appraisal). However, when including the possible extension of the exploration phase, then Lebanon offers the longest duration. With respect to the relinquishment rule, the provision in Lebanon falls on the lower end, except when the extension of the exploration phase is provided, when the relinquishment rule falls on the other end.

Table 3 Duration of petroleum rights in Cyprus, Israel and Lebanon

	Lebanon	Israel	Cyprus
Exploration			
Initial period	3	3	3
2nd Period	2	-	-
1st Renewal Period		Up to 4	2
2nd Renewal Period			2
Total Excluding Appraisal	5	Up to 7	Up to 7
Extension for Appraisal	5	Up to 2	0.5-2
Total	Up to 6	Up to 9	7.5-9
Exploration Phase Extension	Total phase 10		
Relinquishment Rule			
	25%-50%*	Up to 40%	At least 25%
Production			
Phase I: Initial period	25	30	25
Phase II: Extensions	5	20	10
Total	Up to 30	Up to 50	Up to 35

* 25% of Area must be relinquished at the beginning of Second Exploration Period; 50% of Area (cumulative) must be relinquished in case of extension of Exploration Phase

Sources **OPRL Law 132 24/8/2010; Israeli Petroleum Law No 5712-1952; Cyprus Hydrocarbons, Prospection, Exploration and Exploitation Regulations. 2007 and 2009 and 2012 Model PSC**

The treatment of the appraisal time varies between the three countries. In Lebanon, in principle the extension is for one year; in Israel it is for two years. According to the 2012 Model PSC, Cyprus offers six months for the appraisal of an oil discovery and up to two years for a gas discovery. Investors typically need a longer appraisal period for natural gas before declaring a discovery commercial—the latter depends on the availability of sufficient gas reserves and on guaranteeing commercial markets.

There also seems to be wide variations between block sizes across the three countries as well as within the same country (for instance Cyprus).¹⁸ As shown in table 4 and figure 1, Cyprus offers the largest blocks on average, while Israel the smallest.

Lebanon has divided its offshore area into ten blocks, covering what Israel claims to be a disputed area of 854 Km². The size of the blocks, however, has been criticized as too large. In practice, and as discussed in section I. b2., there is no ideal block size: The geological risk, the type of opportunity, and the relinquishment rules should all be taken into consideration.

18 Turkey disputes the blocks delineation made by Cyprus. The analysis of this dispute is for the legal community and goes beyond the purpose of this chapter.

Table 4 Size of block areas in Km²

	Lebanon	Israel	Cyprus
Minimum	1,259	128	1,440
Maximum	2,374	400	5,741
Average	1,790	369	3,920

Sources Deloitte, Israel Opportunity Energy Resources LP, Adira Energy, Zion Oil and Gas.

Figure 1 Comparison of offshore block delineation



Sources Lebanese Petroleum Administration; PetroView®, Israel Opportunity Energy Resources LP; Republic of Cyprus Ministry of Energy, Commerce, Industry and Tourism

II Petroleum Fiscal Regime

The central objective of the upstream petroleum fiscal regime is to acquire for the state in whose legal territory the resources in question lie, a fair share of the wealth accruing from the extraction of that resource, while encouraging investors to ensure optimal economic recovery of the hydrocarbon resources. How to achieve this balance is a subject of enduring controversy.

While the taxation of corporations from any sector is of interest, the taxation of oil and gas merits special attention simply due to the scale of the numbers involved. For prolific oil and gas provinces, annual taxes collected run into billions of US dollars, and globally in the trillions per annum. No other commodity, manufacturing industry, or service sector can offer sustained tax revenues on this scale. In the OECD countries, for instance, all sectors in the economy except the petroleum sector, are subject to an average income tax of 23%, down from 30% in 2000 (OECD 2014). In the oil and gas sector, however, the average government take—that is the total share of government revenues from a project's net cash flows—varies between 65% and 85% (IMF 2012). The underlying reason resides in the special features of the petroleum industry, in particular the fact that these resources are non-renewables and state-owned, with significant potential of economic rent.

But the industry has additional attributes which also need to be taken into consideration when designing the fiscal regime. Substantial uncertainties exist all along the supply chain; of central relevance are those associated with petroleum geology, the specific characteristics of individual fields, and investment returns. The costs of petroleum projects tend to be incurred upfront and the time lags are considerable, often of many years and even decades, from the initial discovery of oil or gas to the time of first production, which can

then last for more than 30 years. That is why it is not just the tax rates that are important; the timing of when various fiscal instruments hit investors is equally relevant.

A common trap that non-fiscal experts often fall into is commenting on a petroleum fiscal regime by looking only at its type, the headline tax rates, or a specific instrument. This is simplistic and inaccurate to say the least, as the type of the fiscal regime does not affect the sharing of potential wealth; it is the combination and interaction of all various instruments that determine the final outcome.

Practitioners in the field of upstream taxation are more familiar with the typical fiscal ingredients that make up the structure of most of the world's tax regimes, which include, royalties, resource rent tax, corporate tax, profit oil/gas, and cost oil/gas. What is less familiar, however, is a wide range of commercial and regulatory obligations placed on investors, which, although in most circumstances are not labeled as taxes, are in effect just that in terms of their economic consequences. These obligations confer additional benefits to the state; they include: State participation, bonus, ring fencing, depreciation, Domestic Market Obligations (DMO), and capital gains tax—all of which affect a project's profitability directly.

The objective of this section is to first describe the main types of fiscal arrangements and their key instruments, and second to conduct an analysis of Lebanon's petroleum fiscal regime and compare it with the regimes of Cyprus and Israel.

a Types of fiscal regimes ¹⁹

Two types of fiscal regimes prevail in oil and gas exploration and production activities: Concessionary and contractual systems. The concessionary system originated at the very beginning of the petroleum industry (mid-1800s) and still predominates in the OECD countries. The contractual regime emerged a century later (mid-1950s), and has been typically favored by developing countries. Australia, Canada, Norway, and the UK, for example, operate a concessionary regime, companies being entitled to the ownership of the petroleum extracted. By contrast, countries like Angola, Azerbaijan, Iraq, and Nigeria apply a contractual regime, whereby the government retains the ownership of the production. Contractual regimes are widely spread among developing countries. Lebanon opted for the contractual arrangement, which is also popular in the region.

Because modern concessionary regimes include various combinations of a royalty, an income tax, and a resource rent tax, they are also known as Royalty and Tax Systems (R&T). The basic features of the oil and gas concessionary regimes are similar, but the fiscal terms or ingredients vary considerably and are likely to evolve over time as a basin matures.

It is tempting to pass judgment on a fiscal regime based solely on its type—concessionary or contractual. Reference is sometimes made to the early 'generous' concessions as an illustration of the unsuitability of the concessionary system from a government's perspective. The establishment of particular fiscal regimes,

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Based on Nakhle (2008a&b).

however, should be considered within the broader conditions that prevailed in the oil industry at a certain period of time. For instance, in the early stages of the industry, exploration was a very risky business (for example, it took 25 years to strike oil in Oman), sizeable reserves had not yet been established, the usefulness of petroleum was only beginning to be recognized and the oil market was relatively small in scale. Competition was limited and a small number of global players dominated the oil industry. Furthermore, early concessions were granted by governments lacking specialized knowledge of petroleum economics, often under foreign political influence and not possessing a cadre of professional staff capable of constructing and implementing a legal and regulatory framework to guide petroleum operations.

Following a series of changes of a political, economic, social, and legal nature, including the nationalizations of the 1960s and '70s, the emergence of OPEC, accelerating oil demand, the opening of new oil provinces, advances in technology, and increased competition, to name but a few, it was inevitable that new agreements would emerge and existing concessions would be revised.

Today there are more fiscal regimes than there are countries and many countries use more than one fiscal structure and regime. Fiscal regimes can be made equivalent in terms of both control and overall economic impact. Variations in tax rates as well as the interaction of different fiscal and non-fiscal instruments—in other words, the way a fiscal regime is designed determines the differences in a project's post-tax economics and risk-reward balance across countries.

1 Concessionary regimes

The basic features of concessionary regimes are similar, but the fiscal terms or ingredients vary considerably and are likely to evolve over time as the fields and basins mature. The main instruments in such arrangements include:

- *Royalty*: It is typically imposed on a specified level of production or on the value of the output or gross revenues. From a government's perspective, a royalty is relatively simple to administer, difficult to avoid, predictable, and provides revenue as soon as production starts. From a company's perspective, a royalty may deter marginal projects, since it is not profit related and is therefore a regressive instrument, whereby the lower a project's profitability, the higher royalty payments are relative to profits. Some governments apply a sliding scale royalty in order to make it more progressive, by linking the rates to production level, oil prices, or project economic milestones such as payback or rate-of-return triggers. These features not only complicate the regime but also fail to address the fundamental drawback, namely that a royalty is still imposed irrespective of cost or underlying project profitability. An additional problem with a sliding scale royalty is that there is no objective yardstick for the scale.
- *Corporate Income Tax (CIT)*: This usually consists of a single-rate structure, levied at a corporate or legal entity basis rather than at the field level. Some countries include the oil industry within the standard CIT regime for all industries, although they may use a higher rate to capture more rent or incorporate additional tax incentives to adapt the system to the specific nature

and needs of petroleum operations. In addition to cost deductions, interest expenses and losses carried forward and/or back are commonly allowed in the computation of the tax base. Most countries provide an incentive for exploration and development by allowing exploration costs to be recovered immediately and allowing accelerated recovery of development costs. Accelerated depreciation brings forward the payback date for the investor.

- *Resource Rent Tax (RRT)*: The tax is levied on a project or field's cash flows and aims to capture a larger share of the economic rent. It is considered to be neutral because it is not paid before a project reaches payback and achieves a certain rate of return. The RRT can take many forms. A common method is based on an R-Factor, which is linked to payback. The RRT applies only when a project reaches a specific ratio. The other method is the use of the Rate of Return (ROR), or the internal rate of return (IRR), as a threshold. The RRT is imposed only when cumulative net cash flows (NCF) turn positive. Negative cumulative NCF are normally uplifted by a specific rate, carried forward in one year and added to the next year's NCF. The accumulation process continues until the cumulative NCF turns positive and at this point the RRT applies. In both methods, if costs rise or prices fall, taxable profits change in sympathy, as does the RRT burden. Some countries opt for multi-tiered RRT rates in order to capture higher rents. The main disadvantages of this method include: How to determine the tiers, additional complexity, and the perceived risk of 'gold plating' (interventions to manage the trigger points), where an acceleration of investment, for instance, can delay the trigger point to a higher RRT.

2 Contractual arrangements

Under typical contractual systems, the oil company is appointed by the government as a contractor for operations in a certain license area. The company operates at its own risk and expense, providing all the financing and technology required for the operation, in return for remuneration if production is successful. It has no right to be paid in the event that discovery and therefore development do not occur.

If the company receives a share of production (after deduction of the government's share), the system is known as a Production Sharing Contract (PSC)—also called a production sharing agreement (PSA)—which is a binding commercial contract between an investor and a state (or its national oil company, NOC). Since the company is rewarded in physical barrels, it takes title to that share of petroleum extracted at the delivery point (export point from the contract area). If the reward is a cash fee, the system is called a service agreement, where, in the case of commercial production, the company is paid a fee (often subject to taxes) for its services without taking title to any petroleum extracted. The service agreement is the least popular; it is found in less than ten countries around the world.

Just like concessionary regimes, contractual regimes can be designed in many different ways, with terms varying both within and across basins. In their most basic form, they include: Cost recovery, profit sharing, service fees, and income tax. It is also increasingly common to include royalties.

- *Cost Recovery*: In the case of a commercial discovery that moves forward to development, the company is allowed to recover the costs it has incurred. The mechanism is called cost recovery or cost oil/gas (cost petroleum), which is similar in concept to deductible expenses for tax purposes under the concessionary system. In any one year there is a fixed proportion of total production that investors can use to recover their costs. If costs exceed the cost recovery limit, the difference is carried forward for recovery in subsequent periods. The ceiling on cost petroleum secures up-front revenues to the government as soon as production commences, in this sense the ceiling achieves a similar outcome to a royalty. Cost recovery limits can be set at a specific rate or variable. The more generous the limit is, the longer it takes for the government to realize its take, while low ceilings can negatively affect the development of marginal fields. Any cost petroleum which is available but not used for cost recovery (i.e. excess cost petroleum) is usually added to the profit sharing pool.
- *Profit Sharing*: Under a PSC, the value of the oil or gas that remains after the company has taken its cost oil/gas is usually termed profit oil/gas. The cost recovery ceiling ensures there is always a minimum quantity of profit oil/gas, which is divided between the host government and the company according to a predetermined percentage agreed to in the contract. The split can be constant, or on a scale linked to cumulative or daily production rates, or to levels of project profitability (ROR, or R-factors). Under a service contract, since the contractor does not receive a share of production, terms such as profit petroleum are not appropriate, even though the arithmetic will often carve out a share of revenue in the same fashion that a PSC shares production.
- *CIT*: Both profit oil/gas and the service fee can be subject to the CIT. In some countries such as Cyprus, the government pays the contracting company's income tax from its share of profit oil; these are called 'pay on behalf' PSCs. Non-tax specialists tend to confuse this aspect with a zero corporate tax rate. Table 5 summarizes the key features of the concessionary and contractual regimes.

Table 5 Key features of concessionary and contractual arrangements

Concessionary	Contractual: PSC	Contractual: Service Contracts
State owns resource; IOC owns production	State owns resource and production; contractor's remuneration is a share of production hence acquires ownership of that share of oil	State owns resource and production; contractor's remuneration is a fixed fee
IOC bears all risk and gets all rewards; pays taxes accordingly	Contractor bears all exploration and development risks; shares commercial (oil price) risks	Contractor bears all exploration and development risks; government takes commercial (oil price) risk

IOC entitlement: gross production less royalty, taxes, bonus	Contractor's entitlement: Cost oil plus profit oil, less income tax	Contractor's entitlement: Cost oil plus remuneration fee, less income tax
IOC owns facilities	State owns facilities	State owns facilities

Investors typically prefer regimes that impose less up-front burden and are more profit-linked, in other words 'progressive'. Instruments such as a royalty, bonus, carried state participation,²⁰ and low cost recovery ceiling, tend to lengthen payback and make the regime more regressive—as overall profitability goes up the government's share of profits goes down and vice versa. However, the latter instruments allow the government to generate revenues as soon as production starts, unlike profit-related taxes. In order to maintain the balance between host governments and investors interests, a combination of several instruments is often used and forms a country's petroleum fiscal regime.

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See Section 3.2.

b Lebanon petroleum fiscal regime

Lebanon's OPRL provides for a PSC as the fiscal framework for oil and gas, although the regime is described by some Lebanese officials as hybrid, mainly because it combines a royalty with profit sharing. In reality, petroleum fiscal regimes have become very elaborate and continue to evolve. Many can be described as hybrids, borrowing features from each other up to the point where the classification of a fiscal regime under a specific terminology has become more difficult, at least from an economic perspective. For example, a royalty is common in concessionary regimes, for it is imposed as compensation for the transfer of ownership of the oil produced—at least that is the theory. In practice, however, a royalty is used to provide an early and relatively predictable flow of tax revenues. As a result, many PSCs around the world have a strong royalty component, even though it is not consistent with the legal nature of such arrangements, since governments retain full production ownership rights. Furthermore, many concessionary regimes today do not have a royalty (e.g. Norway and the UK).

The OPRL does not include the details of fiscal terms, which are given in the EPA instead. There is a debate concerning this practice. International organizations such as the IMF favor the inclusion of the fiscal terms in the hydrocarbon legislation as this reduces administrative costs, political difficulties, investors' perceived risk, and increases transparency. According to the IMF (2012, 36) 'The alternative of setting the fiscal terms out in a model agreement can make them little more than a basis for negotiation.'

At the time of publishing, the EPA decree has yet to be approved by the Council of Ministers, along with the block delineation decree. The following analysis is based on the Model EPA provided by the LPA to the author in February 2014. The author was informed that further revisions have been made, some of which are referred to in the analysis below.

Lebanon's fiscal regime includes: A royalty, cost recovery, profit sharing between the government and the company extracting the resource, income tax

on the company's share, and state participation.

The royalty on oil (and Natural Gas Liquids, NGLs, if any) is imposed on a sliding scale varying with incremental daily production, as shown in table 6. The royalty rate for gas is flat at 4%. The limitations of a royalty were discussed in Section II. a1. A royalty is a regressive instrument as it is imposed irrespective of cost. Linking the royalty rate to production does not overcome this problem since a field size is a poor proxy for profitability. Furthermore, it is unclear on what basis the scale was set.

Table 6 Sliding scale royalty on oil

Daily Oil Production in Barrels Per Day (b/d)	Royalty Rate (%)
< 15,000	5
15,001 - 25,000	6
25,001 - 50,000	7
50,001 - 75,000	8
75,001 - 100,000	10
>100,000	12

Some non-fiscal experts have limited their assessment of the fiscal regime in Lebanon to the royalty and condemned its low rates by international standards. As highlighted in section 3, all the fiscal instruments—their rates and design, as well as the way they interact with other instruments—should be taken into consideration when assessing the petroleum fiscal regime. In Lebanon's case, in particular, special attention should be given to the net impact of the combination of a royalty with a cost recovery ceiling. Furthermore, it is unusual to find high royalty rates imposed on natural gas, as the economics of gas projects are more challenging than those of oil. Lebanon can keep the differentiated rates between oil and gas but it should set a reasonable flat rate for oil instead of the sliding scale.

The cost recovery ceiling is meant to achieve the same objective as the royalty—that is to generate revenues for the government as soon as production starts. The application of a royalty, however, will delay the cost recovery for investors and further extends the payback period. The disposable petroleum (the net revenues available for cost recovery after the royalty payment) will be partly used by the contractor for cost recovery, depending on the level of the ceiling. Therefore, when a royalty applies, it reduces the amount of petroleum available for cost recovery, which in turn lengthens the cost recovery period.

According to the February 2014 version of the EPA, the cost recovery ceiling was supposed to be one of the biddable parameters, along with profit sharing, which is on a sliding scale related to profitability (R-factor) (table 7). Having such key fiscal parameters biddable was one concerning feature of the regime. It is unusual to see the minimum profit sharing biddable. This can lead to a wide range of minimum government takes, consequently increasing the administrative burden and complicating revenue forecasting.

The R-factor is calculated on a quarterly basis as the ratio between Cumulative Cash Inflow and Cumulative CAPEX, whereby Cumulative Cash Inflow equals profit petroleum plus cost petroleum less OPEX, from the beginning of the production phase through the end of the quarter. The profit-sharing mechanism should make the regime more progressive although the final outcome will depend on the rates and interaction of different instruments.

Some countries adopt a single rate for profit sharing since the mechanism is based on profits, not revenues, meaning a single rate will still safeguard the progressivity of the system and an application of several bands is therefore deemed unnecessary. The inclusion of tiers became more fashionable as a single rate was found hard to determine. Furthermore, if countries use different bands for profit sharing and make them biddable, international good practice recommends fixing the minimum band and allowing companies to bid on the higher tiers (section II. b).

It is unusual to see the minimum profit sharing biddable especially since it can lead to a wide range of minimum government takes, thereby increasing the administrative burden and complicating revenue forecasting. Lebanon could improve its system by fixing the lower band of its share of profit petroleum and allowing companies to bid for two more upper tiers. The advantage of this approach is that it ensures a minimum government share of profit petroleum, rather than solely relying on the bidding process.

According to the LPA, the maximum for the cost recovery ceiling and the minimum for the profit sharing have now been fixed, following recommendations from the IMF—a move that is welcomed by the author.

Table 7 R-Factor and profit sharing rates

R-factor < 1	A% (biddable)
1 < R-factor < RB (biddable)	Between A% and B%, according to a formula
R-factor > RB (biddable)	B% (biddable)

According to the Model EPA, when the R-factor is between 1 and RB, the state share of profit petroleum will be determined according to the following formula: $A + [(B-A) \times (R - 1) / (RB - 1)]$; where A and B are the minimum and maximum state shares of profit petroleum.

Originally, there was some ambiguity with respect to the CIT rate with some parties calling for using the general income tax rate of 15% on the contractor's total share of profit petroleum, as a starting point for the draft taxation law to be finalized by the Ministry of Finance. Others have argued in favor of increasing the income tax rate on petroleum activities to 25%.

Once again, it is difficult to comment on these rates, as it is the total impact of the regime that matters most, not the rate of individual instruments. Many experts prefer the imposition of the general CIT rate on the oil industry, instead of treating it differently and complicating the regime. If that practice is adopted, the authorities should amend the Income Tax Law to take into consideration the special features of oil and gas operations. Consistency should also be maintained

between the Income Tax Law and the EPA, especially with respect to cost recovery and deductions of expenses. For instance, while finance costs are tax deductible, they are not cost recoverable.

At the time of publishing, the LPA is collaborating with the Ministry of Finance to decide on an appropriate income tax rate and finalize the petroleum taxation law to be presented to the Council of Ministers and then the parliament for ratifications.

Contractors pay a fee for the training of public sector personnel with functions relating to the oil and gas sector, in an amount up to \$300,000 per year (increased by 5% each year) until the beginning of the production phase, and thereafter \$500,000 per year (increased by 5% each year). These costs are recoverable.

Some concerns have been expressed about the local employment requirement where, according to the Model EPA (Article 20) 'as of the beginning of the Production Phase, no less than 80% of the aggregate number of employees of the Right Holders (including the Operator) shall be Lebanese nationals.' Some companies fear that this threshold may not be easy to reach given the limited oil and gas expertise in the country.

The OPRL refers to state participation (Article 6), as a 'back-in right' option where the state maintains the right to acquire a given interest following the declaration of a commercial discovery. This is the typical form for state participation although there are examples where the state pays its way. Under the former option, the state does not contribute its share of costs and is carried by the IOC, during the exploration period, until a commercial discovery is declared or until first revenues flow at first production. The risk is that no commercial discoveries are made, in which case the carried costs are never recovered. State-carried interests can be very expensive for IOCs, particularly in high-cost areas, such as deep water. Furthermore, carried state participation extends the cost recovery period as the carried costs are recovered from the state/NOC's equity share of production until the carry is repaid. Generally, IOCs do not favor such arrangements since they materially increase the exploration risk (cost of failure) and reduce the project's economics, especially when combined with tough fiscal terms.

In Lebanon, the state participation provision will not be enacted in the first licensing round. Its rate and form are still to be determined. If enacted, and depending on its form, state participation will increase the overall government take in the venture.

There are still some unknowns that prohibit a full assessment of Lebanon's upstream petroleum fiscal regime. Two important aspects should be taken into consideration. First, whatever combination of rates Lebanon selects, the fiscal regime should be internationally competitive and the total government take can be in line with the global average of 65% to 85%. As put by the IMF (2012, 6) 'fiscal regimes that raise less than these benchmark averages may be cause for concern, or—where agreements cannot reasonably be changed—regret.' Higher rates are also not recommended as they can deter the attractiveness of the country to IOCs. Second, investors are not only concerned by the level of

government take; they put perhaps equal emphasis on the extent to which the regime imposes upfront burden on their projects.

c Comparison of regional fiscal terms

This section analyzes the petroleum fiscal terms in Cyprus and Israel and compares them to Lebanon.

1 Cyprus petroleum fiscal regime

Like Lebanon, Cyprus adopted a PSC. It is also difficult to conduct a detailed analysis of the Cyprus petroleum fiscal regime as all fiscal terms are biddable or negotiable and none of the signed contracts have been made public.

Cyprus does not have a royalty but imposes signature and production bonuses. This can be partly explained by Cyprus's urgent need for cash given its economic crisis. The government imposes a ceiling on its cost recovery and profit sharing based on the R-factor. The general CIT rate is imposed on the contractor's share of profit petroleum but it is paid on its behalf.

The following terms have been referred to in the 2012 Model Production Sharing Contract issued in connection with the second licensing round:

- Signature and production bonus: The former is paid within thirty days after the date of execution of the contract while the latter within thirty days after average daily production from the contract area measured over sixty consecutive days meets biddable production thresholds.
- The cost recovery ceiling is biddable. Unrecovered costs may be carried forward indefinitely until fully recovered but not beyond the duration of the contract.
- Profit sharing is biddable; it is done on a biddable, incremental sliding scale linked to R-factor, which is calculated quarterly as follows:

$R\text{-factor} = \text{Cumulative Net Revenue} / \text{Cumulative Capital Costs}$ where:

- Cumulative Net Revenue is the contractor's Cost Recovery plus Profit Share less Operating Costs incurred from the start of the project until the end of the preceding quarter.
- Cumulative Capital Costs are the contractor's exploration and development capital costs incurred from the start of the project until the end of the preceding quarter.

Under the 2007 Model Agreement used for the First Licensing Round, profit sharing was based on an incremental sliding scale linked to average daily production rates and the price of oil.

- CIT: There is no specific regime within the Cypriot income tax law concerning the oil and gas sector. CIT is paid by the state from its share of production; it is the normal CIT rate of 10%. Confusion arose in the second licensing round when the model PSC was released without a tax clause following continued statements by the Ministry of Commerce that 'no tax is payable' on oil and gas production profits. By contrast, the 2007 Model PSC includes a tax clause providing that 'applicable corporate tax shall be deemed to be included in the Republic of Cyprus's share of Profit Oil' and 'the portion of Available Oil which the contractor is entitled to ... shall be net of corporate tax' (Mallis 2012). The ministry had to

post a clarification that each second round PSC would include a similar clause, although 'a statement showing the amount of corporate tax paid for each specific calendar or tax year cannot be prepared or obtained.' The latter has important implications for international investors. When 'pay on behalf' is used, the precise legal provisions are important in the context of assessing the foreign tax credit position of IOCs, which may give rise to additional tax liability in their home country if poorly constructed.

- Training Fee: The contractor is required to contribute negotiable/biddable amounts toward the training of Cypriot civil servants. The amounts may be different in the periods before and after the declaration of commerciality. Training fees are cost recoverable.

2 Israel petroleum fiscal regime

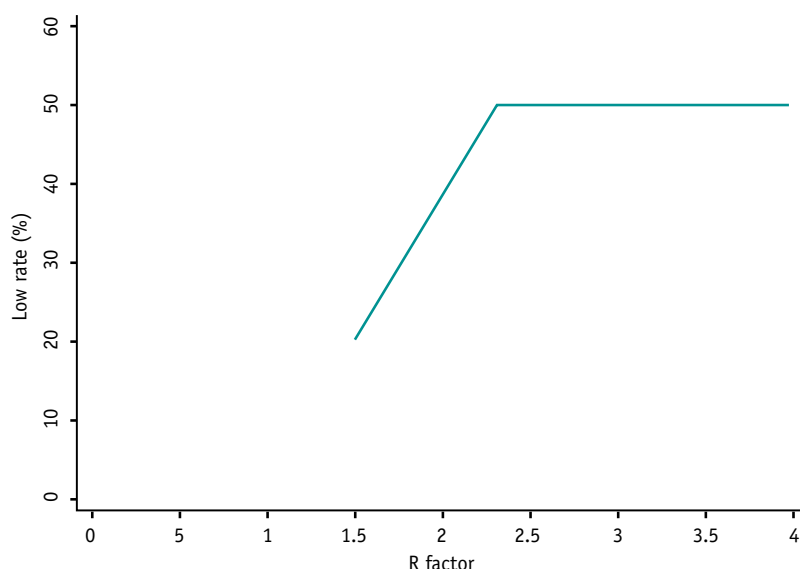
Israel illustrates a typical example of the fiscal cycle. In untested offshore environments in particular, governments are likely to adopt a cautious attitude and offer attractive fiscal terms to arouse sufficient interest from IOCs and as a spur to kick-start activity. Once discoveries are made, host governments feel empowered as it becomes clear that a hydrocarbon basin exists. Often, such an outcome leads to tightening regulations and fiscal terms.

Israel applies a concessionary regime, formulated in 1952 and largely left unchanged for decades until 2011. The original fiscal regime was very generous from an investor's perspective, whereby the government's take at only about 30% was one of the lowest in the world. That level was deemed inappropriate and the regime obsolete following a series of gas discoveries. The original system included: Fees, a royalty, CIT, and special deductions for depletion. Such a combination made the regime regressive.

In 2010, the minister of finance appointed the Sheshinski committee to examine the country's petroleum fiscal regime. The committee found that 'the current system does not properly reflect the public's ownership of its natural resources' (Ratner 2011, 7). The committee's draft conclusions recommended two major changes to Israel's tax treatment of the oil and gas industry:

- First, eliminating the existing depletion deduction, which the committee describes as an anomaly in the legislation and lacks any economic justification. The depletion allows taxpayers to deduct from their taxable income (gross revenues less royalty) about 27.5% for a reduction in a product's reserves, thereby cutting their tax liability.
- Second, introducing a progressive special profit tax (or windfall tax), based on an R-factor of a minimum of 1.5 and a maximum of 2.3. The tax rate would begin at 20% when cumulative net cumulative income is equal to 150% of its exploration and development costs. It then increases linearly up to a maximum of 50% (imposed when the R-factor reaches 2.3), as shown in figure 2.

Figure 2 R-Factor & windfall tax rate



The committee also recommended keeping the royalty rate at 12.5% (deductible from the income tax base). Additionally, the regular income tax rate applies to oil and gas corporations (whether registered as an Israeli company or as a foreign company operating in Israel). The rate applies at 26.5% effective from 1 January 2014, compared to 25% in 2013 (E&Y 2014).

Accordingly, and following the above changes, the government fiscal take would vary between 52% and 62%, which is below the world average. Johnston (2010, 4) describes Israel's new fiscal regime as 'state-of-the-art in fiscal design' and 'one of the more progressive systems in the world.'

Table 8 summarizes the key features of the petroleum fiscal regimes in Lebanon, Cyprus, and Israel. Apart from Israel, it is difficult to identify a rate (or a range of rates) for the government take in Lebanon and Cyprus. In the former, the fiscal terms are yet to be finalized and some key fiscal terms are biddable. In the latter all terms, apart from the CIT, are biddable.

Table 8 Summary of economic terms

	Lebanon	Cyprus	Israel
Type	PSC	PSC	Concessionary
Royalty	4% gas 5-12% sliding scale with production	None	12.5%
Signature Bonus	None		None
Production Bonus	None		None
State Participation	Applicable but not in 1st round	None	None
Windfall Tax	None	None	20-50% R factor based
Cost Recovery Ceiling	Biddable	Biddable	None

Profit Sharing	Biddable	Biddable 1st Round: based on production and price for oil; based on production tiers for gas 2nd round: based on R factor	None
CIT	15%	10% paid on behalf	26.5%
Training Fee	Up to \$300,000/year (increasing by 5% annually) until beginning of Production; thereafter \$500,000/year (increasing by 5% annually)	Biddable	None

3 Additional features

The design of a fiscal regime should take into consideration the conditions of the oil and gas region. A high level of government take may not be justified in cases of high-risk exploration and high-cost development, or for those areas with remaining modest petroleum potential. From an investor's perspective, a combination of commercial and non-commercial factors comes into play when assessing the competitiveness and attractiveness of an oil and gas province. Investors seek to achieve reasonable returns at an acceptable level of risk. They compare the expenditures to be incurred with the potential rewards. The evaluation looks at factors such as geological potential, commercial prospectivity, political risks, and of course, fiscal terms. The end result of this process permits opportunities to be ranked across the global portfolio. Experience also shows that low levels of government take are rarely stable.

Other important features of a fiscal regime include its simplicity and stability. Simple regimes reduce the administrative burden. A tax regime that is simple to understand, implement, and administer is levied on a well-defined tax base. It increases transparency and reduces the administrative burden, for both administrations and the taxpaying businesses. The more transparent the means by which the government obtains revenues, the better informed the investors and the less the scope for maladministration or administrative discretion.

Unstable fiscal regimes negatively affect the confidence of investors in government policy. Of course, fiscal regimes cannot be expected to be set in stone. Circumstances are constantly changing in any basin. A certain degree of flexibility needs to be allowed in any tax system if it is to respond to differing conditions, such as maturity, and to evolve as a result of major changes in the external environment. However, if a tax system changes frequently and unpredictably, it may seriously affect future development projects since it increases political risk and reduces the value placed by investors on future income streams. It is recommended that the variation of taxes over the life of a project can be minimized and as such it is imperative to get things right from the beginning.

The design of a progressive regime allows the system to respond automatically to changes in conditions, giving investors greater predictability. Emphasis on stability is equally important to governments. A tax system that has some level of predictability and reliability enables governments to know how much revenue will be collected and when, clearly assisting with reliable expenditure forecasting and budgeting.

The adoption of profit sharing linked to the R-factor makes the Lebanese fiscal regime more progressive. However, this progressivity should be weighed against the other regressive instruments in the regime, namely the royalty and cost recovery ceiling.

Conclusion and Recommendations

The paper analyzes the choices that Lebanon has made in terms of awarding oil and gas contracts and the upstream fiscal regime and compares them to policies adopted in Cyprus and Israel.

In terms of the allocation strategy, Lebanon selected competitive bidding, which is increasingly popular as it allows host governments to benefit from the competitive instinct of IOCs. The popularity of auctions is likely to continue, especially as many NGOs promote their use under the argument that they are the most transparent procedures. However, the success or failure of an auction largely depends on its design and a government's commitment to transparency. Countries can adopt a range of allocation policies because a single strategy may not be suitable to all circumstances and opportunities. An important aspect of competitive bidding is the choice of the biddable parameters where the use of fiscal parameters is not recommended—a consideration that the LPA has made in its latest revisions of the EPA.

In terms of block delineation, Lebanon offshore block sizes do not fall outside the reasonable range, especially when the exploration risk and the relinquishment rule are taken into consideration.

With respect to petroleum regulations, Lebanon seems to offer a middle ground between Cyprus and Israel—the former being more lenient, while the latter is becoming more prescriptive especially after the 2010 and 2011 changes.

Some question whether the choice of regime Lebanon made is the right one. In reality, the type of the regime is less relevant. Fiscal regimes can be made equivalent in terms of both control and overall economic impact, for given oil and gas prices. The design of the regime, the interactions of different fiscal and quasi fiscal instruments, the details related to the imposition of different instruments, among others, are by far more important. Limiting the assessment of the effectiveness or strengths of the fiscal regime to the choice and rate of the major headline taxes is restrictive. Several factors, such as the fiscal reliefs and the process of calculating the tax base can lead to significant differences among fiscal packages, while different structures and regimes can produce the same results in terms of revenue and tax take.

Apart from Israel, it is difficult to identify a rate (or a range of rates) for the government take in Lebanon and Cyprus: In the former, the fiscal terms are yet to be finalized and published. In the latter all terms, apart from the CIT,

are biddable. After more than sixty years Israel introduced new fiscal changes in 2012. These made the regime more progressive and remain competitive by international standards. Cyprus does not impose a royalty, but uses signature and production bonuses along a biddable cost recovery ceiling. The island changed its fiscal terms in the second licensing round, especially with respect to the profit sharing basis.

While the overall government take is important, the timing of when tax instruments hit investors, and therefore affect their payback, is equally relevant. The best investor incentive is probably the chance of rapid payback of capital. In Lebanon, the combination of royalty and cost recovery ceiling, with the possibility of state participation, can result in lengthening the payback period and make the regime more regressive.

No single, ideal solution exists for all countries. The perfect fiscal regime has yet to be invented. What matters is what governments want to achieve. Since there is no objective yardstick for sharing economic wealth between the various interests involved in petroleum activity, controversy and tensions will always prevail between investors and the host government. It is important, however, to maintain the delicate balance between ensuring an adequate share of revenues for tax-levying authority while simultaneously providing sufficient incentives to encourage investment. These issues arise in almost all taxation policy activities but in the case of oil and gas, they assume a special character and complexity.

There are still several unknowns that prohibit a full assessment of Lebanon's upstream petroleum fiscal regime. Whatever combination of rates and instrument Lebanon selects, the fiscal regime should be internationally competitive.

Recommendations for Lebanon:

This paper's recommendations for improving the existing system in Lebanon focus on three specific areas:

Law:

- The government should consider adopting one law that governs offshore and onshore operations, should the latter be considered. This is in line with international practice. It can also offer the opportunity to fill the gaps in the OPRL, particularly the inclusion of the details of the fiscal regime now that the authorities have had sufficient time for thorough analysis.

Licensing:

- The government needs to ensure that licenses are allocated in a climate of transparency and openness and meet the highest standard of professionalism and adherence to international practice.
- The issues of license duration and extension would benefit from further clarification, otherwise they can lead to different interpretations. The division of periods and formulation of extensions and relinquishment rules could have been made much simpler.
- It is advisable that Lebanon does not award all its blocks simultaneously.

- Blocks should be awarded to companies that submit the most appropriate bids, not necessarily the most optimistic ones. To minimize the risk of overcapitalization, which could result from a biddable work program, Lebanon should have a highly qualified and skilled committee evaluate various offers.
- The block sizes are average compared to what Cyprus and Israel offer. There is no ideal block size: The geological risk, the type of opportunity, and the relinquishment rules should also be taken into consideration.

Fiscal Regime:

- Lebanon should consider including the details of the fiscal terms in the OPRL, not just in the EPA.
- Originally, the main weakness of the fiscal regime was the fact that two important parameters—the cost recovery ceiling and the profit sharing—are proposed to be biddable. It is unusual to see the minimum profit sharing biddable, especially since it can lead to a wide range of minimum government takes. The author welcomes the subsequent revisions introduced by the LPA, mainly to fix the maximum cost recovery ceiling and the minimum profit sharing.
- Some non-fiscal experts have limited their assessment of the fiscal regime in Lebanon to one instrument (royalty or CIT). In reality, all fiscal instruments—their rates and design, as well as the way they interact with other instruments—should be taken into consideration when assessing the regime. Special attention should be given to the net impact of the combination of a royalty with a cost recovery ceiling.
- The government can impose a single royalty rate for oil, while maintaining the differentiated rates between oil and gas. It is the R-factor that will provide flexibility to the system, in line with changing costs and profitability.
- R-factor-based profit sharing should make the regime more progressive although the final outcome will depend on the rates and interaction of different instruments.
- The CIT rate is yet to be finalized. International practice tends to support the imposition of the general CIT rate on the oil industry, instead of creating a separate regime. Some amendments to the Income Tax Law are needed to take into consideration the special features of oil and gas operations.
- Consistency should be ensured between the Income Tax Law and the EPA.

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