Risks, Taxation, Investment Decisions in the Offshore Oil and Gas Sector.

Black Sea and Romania

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Executive summary

The goal of the present study is to contribute data and arguments to the debate that is taking place at the moment in Romanian politics, the media and the society at large on the potential of offshore natural gas in Romania’s deep waters of the Black Sea. To facilitate a comprehensive and realistic approach, the study provides a detailed picture of the risks that deep offshore oil and gas projects face. The ability of investors to manage such a risk array determines their investment decisions and the progress of their projects.

The development of the offshore gas sector represents a historic opportunity for Romania, as it can bring major economic, social and energy security benefits. The adoption of a fair and stable regulatory framework for the offshore sector, that will enable the start of development and production works, is a strategic imperative. The political decisions to be made in the upcoming months are decisive for the future of this economic sector of crucial importance.

The extraction of the Black Sea gas resources would be part of an international trend of increase of the share of deep-sea oil and gas in the total hydrocarbon production in order to meet the growing global demand. The anticipated annual growth rate to 2040 is about 1.6% for natural gas and 0.5% for oil, according to IEA (2017).

Oil and gas production in deep waters has developed over the past two decades and has increased with growing demand, high oil prices, declining production in conventional fields, and technology advances. With few exceptions, the production of such deposits is done by a handful of large international oil companies (IOCs), also called supermajors, acting as a mix of investment banks – able to access enormous financial resources – and technology and management companies.

The vast majority of the larger deep offshore reserves discovered in recent years is located in areas difficult to explore and exploit: the Arctic Ocean, the Atlantic, East Africa, Western Australia etc. Only about 30% of offshore resources have been explored so far. The needed investment per deposit is, roughly, $10 bn, but it can reach $30-50 bn, as in the case of the Kashagan Field - Phase 1 (Kazakhstan). Petrobras’s business plan to develop the Campos Basin in the South Atlantic has rested on a $225 billion investment plan.

At the level of the world’s largest regional basins, the biggest offshore investments between 2010 and 2018 were made, according to Rystad Energy, in Asia-Australia-Russia ($374 bn), followed by Northern Europe (the North Sea, Sea of Norway and Barents Sea) with $217 bn, the Middle East ($198 bn), North America ($133 bn), Africa ($88 bn), and South America ($49 bn).

There has been a marked increase in the costs of deep-sea O&G projects. Drilling an offshore exploration well costs $100-180 million, compared to $5-10 million onshore, but it can also reach $250 million. This is because rigs, platforms, equipment, and very expensive vessels are required to operate safely at 2000m underneath the sea level, at pressure of 200 bar in anoxic environments and seas swept by violent storms or low temperatures. Investments in the sector are characterized by long duration (30-40 years), very high value ($10-40 bn), and significant operations’ safety challenges. Some companies have even risked their viability or their very existence with one single project. Understanding and controlling risks is essential for investors and financiers. In line with classical investment principles, the higher the overall risk degree, the higher the returns that investors expect.

In order to mitigate risk, companies in the sector build diversified project portfolios. Not all the projects are successful, but those that eventually succeed must compensate for the lost bets. In all cases, investments are recovered only after years of operations.

The risks of deep-sea O&G projects are manifold: uncertainty about resource potential, infrastructure and logistics risk, commercial risk, project management risk, environmental risk, reputational risk, political risk, fiscal risk, regulatory risk, weather risk and terrorist risk.

Few economic sectors face so many types of risk. The total risk results as the weighted average of all component risks. Based on the principle that the
strength of a chain is in the weakest link, a project can fail if only one risk factor becomes determinant. Recent history has seen quite a few failed projects in the sector, from Royal Dutch Shell’s abandonment of projects deployed in the Arctic to Gazprom, Statoil and Total’s abandonment of the Shtockman project, and to the enormous cost overruns of the Kashagan project.

In general, investors expect and are able to manage the risks related to geology, technology and know-how, financing, general operational costs, and commercial risk, yet not the political and regulatory risks, including the fiscal one. This is because the latter have to do exclusively with the behavior of the host state. Risks associated with an unstable and unpredictable fiscal environment have a major impact on the investment’s overall risk profile and expected returns. It is paramount for investors to have a stable fiscal framework, given that the investments are of very high value and for the long-term.

At the same time, stability is also important for governments, who get a higher share of oil revenues when regulatory risks, in general, and fiscal risks, in particular, are reduced. Recent experience shows that fiscal instability leads to lose-lose situations as well as to the decline of the host country’s competitiveness and, in extreme situations, to significant budget revenue losses.

Many have drawn parallels between the Black Sea and the North Sea, in terms of O&G resources. However, at this stage, the Black Sea hydrocarbons’ potential is rather theoretical, as geological exploration is still in incipient phase. More important discoveries have been made so far only in the Romanian area. In Turkey and Bulgaria, significant efforts have not been successful.

O&G projects in the Black Sea evince virtually all the general risks of deep-sea offshore, namely:

- Success rates for exploitation of around 20-25% in the case of Romania – but of 0% so far for Turkey and Bulgaria. The drilling costs of such a exploitation are between $150 and 250 million;
- High commercial and infrastructure/logistics risk, because of poor connection to regional markets;
- Limited offshore project management experience;
- Increased geopolitical risk on account of the political and military situation in Crimea and Eastern Ukraine, as well as the current antagonism between NATO and Russia, with Turkey in a tense relationship with its Western allies;
- High and growing fiscal and regulatory risk; lack of stability and predictability of regulations;
- Significant environmental risk of offshore operations, given that the Black Sea is swept by violent storms.

Besides, there are specific risks for the Black Sea:

- It is a quasi-closed sea, with difficult access through the Bosphorus, hence with major difficulties in transporting machinery and equipment;
- Insufficiently known topography of sea bottom, which is also unstable;
- Anoxic conditions deeper than 200 meters, with presence of hydrogen sulfide, which requires special expensive equipment;
- Presence of methane hydrate on the seabed, which poses a fire risk and a threat to the buoyancy of the ships, in case it reaches the surface.
Consequently, the total risk for offshore activities in the Black Sea is significant. On the one hand, this renders exploration less intense; on the other hand, the returns for investors is in line with total risk. In this context, some of the exploration works carried out in Romania in recent years have resulted in discoveries, but which have not yet been declared commercial. A significant number of dry wells were also drilled in different blocks.

The Black Sea risk array applies in its entirety to Romania. One of the most important types of risk is the fiscal one. The recent legislative proposal of the Romanian Parliament, of July 2018, for offshore O&G operations would have brought, if ratified, a higher level of unpredictability and reduced the competitiveness of the regulatory framework. From the fiscal viewpoint, the legislative proposal introduces, in addition to royalties, a progressive income tax, which varies between 15 and 50% according to the gas price. At the same time, the bill provides a 60% deductibility limit on investment from the “supplementary” income resulting from the sale of gas at prices higher than a reference level. But such an approach discourages investment, since it does not allow deductibility of the expenditure made mostly before production start, but is instead limited to the investments done in the month the additional revenue is made, without a mechanism to carry it forward. Moreover, royalties are not deducted from the tax base, as is typically the case in international practice.

With such a change in the offshore fiscal framework, Romania would be ranked second by level of taxation among the countries of the Wider Black Sea Region, after Azerbaijan (which, however, has better operational conditions) and before Kazakhstan, Ukraine and Bulgaria. This potential tax increase would come just as some countries of the region (e.g. Kazakhstan and Ukraine) are increasing their competitiveness through tax cuts for the offshore sector. Moreover, the proposal has been made in a context of already increased O&G taxation in Romania, following the provisions of Emergency Ordinances (OG) No. 7/2013 and, respectively, No. 6/2013. Thus, Romania has moved against the grain of the European O&G tax trends, characterized by lowered average rates of royalties and other taxes on the upstream sector, amid a sharp fall in the price of oil and gas between 2014 and 2017.

Under these circumstances, in order for Romania to maintain competitiveness of its offshore sector, any additional taxation should have a balanced structure and level. At the same time, and the formula setting the royalties' value ought to be adapted to the specifics of this sector. Clarifying and improving the fiscal framework can lead to a reduction of the total risk, and thus to a higher government take, with sufficient return for investors.

At the time of writing, the Romanian Senate approved an amendment introducing in the Offshore Law a stability clause with strict provisions: “The royalty regime and the level of taxation [...] will not change in favor of or at the expense of the holders of the agreements, throughout the period of the agreements and subsequent extensions.” In addition, it creates the possibility of full deduction from the taxes imposed on operators to the “cumulative amount of upstream investments registered in the accounting records according to the regulations in force [...].” Such revisions can play a key role in favoring investment decisions in the Romanian offshore.
Introduction

For some time now, there has been a great deal of debate both in politics as well as the press and the Romanian society about the natural gas potential from the deepwater offshore perimeters pertaining to the Romanian exclusive economic zone in the Black Sea. The debate and emotions focus especially on the sharing of profits between the state and the investors, different opinions being bandied about in the public space – sometimes quite radical – regarding the conditions in which these investments should be carried, the resource potential of the offshore Romanian sector, the exploitation of the resulted natural gas, etc.

This study’s purpose is to provide data and arguments for a realistic assessment of the risks that are taken into consideration when making investment decisions in deepwater offshore projects, as well as in the smooth development of petroleum contracts throughout the concessions’ duration. Even though the fiscal terms play an essential role, there is a series of other risk factors that must be taken into account.

The authors’ firm belief is that the development of the natural gas offshore sector is a historic occasion for Romania, with important benefits from an economic, political and energy security standpoint. The national production of natural gas is facing an accentuated decline of the reserve-replacement ratio, which means that, absent new deposits being put into production, the import dependency will grow from one year to another, and the supply security will be increasingly difficult to ensure. Under these conditions, adopting a fair and stable regulatory framework for offshore operations to allow the initiation of development and production works is a must for the national economy. The future of a fundamentally important economic sector for Romania depends on the political decision which is to be made in the following weeks and months.
Deepwater offshore production is more and more important to meeting the global demand for crude oil and natural gas

The analysis starts from the projection of oil and gas global demand evolution\(^1\) and from the ways to meet such a demand. The International Energy Agency’s (IEA) (2017) projections\(^2\) by 2040, carried out in the central analysis scenario (New Policies Scenario), show an increase in the global gas demand from 3,650 bcm in 2016 to 5,304 bcm in 2040. In this scenario, the annual growth rate in global gas demand will be 1.6% per year, considerably higher than for crude oil, 0.5% per year (IEA 2017, 337).

The growing demand will stimulate the exploitation of offshore resources – mainly of those that are currently in production, but also of new ones (greenfield), including in deepwater areas, but also of onshore unconventional resources, given the decline of conventional deposits production. There is a similar trend for natural gas, as meeting gas demand will mainly be rendered by the production of unconventional deposits, and also by deepwater offshore perimeters. From 2010 to 2016, the global gas demand has experienced an aggregate increase of 1.5% per year\(^3\).

The natural gas market continues to be divided into three main regional blocks: America, Europe and Asia, with liquefied natural gas (LNG) working as a linkage factor, which contributes to the price convergence of the regional markets and, thus, to the shaping of a global market. At present, the LNG market represents roughly 30% of the natural gas global trade.

Offshore Exploitation of Crude Oil and Natural Gas Resources

Deep sea and ocean waters are some of the most difficultly accessible areas, with large unexploited natural resources. However, they have become more attractive, as the growing consumption and high prices of the late 2000s have supported the development of the necessary technologies. Offshore exploitations started to become significant in the 1970s-80s, when the largest deposits in shallow waters were discovered.

It was common practice in the 1970s for offshore activities to take place at depths below 200m – the normal depth for the continental shelf’s edge. Beyond this limit of the shelf there is a steep collapse of the underwater relief, reaching depths of hundreds and even thousands meters. That’s where the deep waters begin, an area where the drilling technology was able to reach only in the early 1990s. As the reserves easier to discover and exploit started to deplete, the international oil companies (IOCs)\(^4\), also called supermajors, focused on increasingly deeper waters and the natural gas share from the total discoveries grew, to the crude oil’s detriment.

As the reserves easier to discover and exploit went on a downward trend, the operations moved into deeper and deeper waters and the natural gas share from the total discoveries grew over oil (Chart 1).

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1. Herein, the term petroleum is used to mean the production of crude oil and natural gas.
3. Iuga, Vasile and Radu Dudău (2018), Perspectivele gazelor naturale în România și modalități de valorificare superioară a acestora, lune
4. International oil companies, also known as supermajors, are large private oil and natural gas companies, listed and capitalized on the stock market, managing global hydrocarbon exploitation, development, production, refining and trading operations. The most important are ExxonMobil, BP, Chevron, Eni SpA, Royal Dutch Shell and Total.
Daniel Yergin (2011)\(^6\) tells the story of a handful of companies which tried, during the early 1990s, to get beyond the shallow waters barrier. In 1992, Petrobras managed to set up an oil platform in the Campos Basin, in the open sea of the Brazilian exclusive economic zone, at an 808m depth. Two years later, Shell was setting up an oil platform in the Gulf of Mexico at a depth of 873m.

This was only the beginning:

“The growth of the global deepwater sector was extraordinary – from 1.5 million barrels a day in 2000 to 5 million by 2009. By that point, some 14,000 exploratory and production wells had been drilled in deep waters around the world. It became customary to describe deep-water production as the great new frontier for the world industry. Among the most prospective areas were at the corners of what is was called the Golden Triangle – the waters off Brazil and West Africa and the Gulf of Mexico. By 2009 the shallow and deep waters from the Gulf of Mexico together were supplying 30 percent of U.S. domestic production. That year, for the first time since 1991, the American oil production grew, instead of declining, and the deepwater was the largest single source of growth. In fact, in 2009, the Gulf of Mexico was the fastest-growing oil province in the world.” (Yergin 2011, 472-473)

\(^5\) Bernstein Energy, The Significance of Deepwater to Global Supply, 2012
National oil companies (NOCs) are large oil and gas companies, owned fully or in the majority by a national government. About three quarters of the global hydrocarbon production is provided by NOCs, which have access to no less than 90% of the proven reserves. The largest NOCs are Saudi Aramco, Rosneft, Gazprom, Abu Dhabi National Oil Company, National Iranian Oil Company, China National Petroleum Corporation et al.

In the Santos Basin, Petrobras applied exploration and extraction technology under a two-kilometre thick layer of salt to develop two massive fields, Parati and Tupi. In order to have access to the second one, Petrobras had to drill a well through 1,800m of water and another 4,500m beneath the sea floor. It cost hundreds of millions of dollars, but it was worth it:

“That well had discovered a supergiant field – at least 5 to 8 bn barrels of recoverable reserves – the biggest discovery since Kashagan in Kazakhstan in 2000. As other wells have been drilled, it has become clear that the presalt in the Santos Basin could become a huge new source of oil. Brazil’s then president at that time, Luiz Inacio Lula da Silva, described it as ‘a second independence for Brazil.’” (Yergin 2011, 487)

The exploitation of deepwater offshore fields is, with the exception of Petrobras and Statoil, the IOCs’ privilege. These companies own only 10% of the global proved reserves, with the remaining 90% owned by the national energy companies (NOC). Most reserves owned by IOCs are located in frontier areas, with high extraction costs, whilst NOCs generally exploit conventional deposits, much cheaper to exploit, the "jelly donut" type, like the ones in the Middle East.

Supermajors are world leaders in the exploration and production technology, acting like a mix of investment banks, capable of mobilizing huge financial resources for exploration and exploitation projects and technology, and project management companies, which maintain their competitive advantage through know-how and innovation. It is perhaps no coincidence that these companies are coming from the Anglo-Saxon economic space, which is dynamic and competitive, encouraging and rewarding innovation.

From a geographical distribution viewpoint, the deepwater offshore reserves discovered in recent years are mainly located in areas that are difficult to explore and exploit, posing great challenges (Map 1). For example, in the Arctic region, operations are done under extreme conditions, under the ice floe, at great depths, while the Gulf of Mexico is a region frequently affected by hurricanes. The Santos Basin is in the middle of the Atlantic, between Brazil and West Africa, a region affected by violent storms. This 500-mile long and 100-mile wide (the depth at which hydrocarbons are found lies 5,000m beneath the sea floor) passageway houses an enormous deposit, estimated to contain 100 bn barrels of oil. However, the middle of the Atlantic also poses serious challenges, such as the water depth (below 2,500 m) and the great distance from the mainland. The O&G exploitations carried out in East and West Africa (with 46 discoveries) are in the same situation, located in regions which are notorious for their political instability.

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In South-East Asia, the 17 recent discoveries are located in a region of growing geopolitical temperature and with disputes on the exclusive economic zones among China, Japan, Vietnam, Malaysia and the Philippines.

Map 1: Location of the deepwater deposits discovered over the recent years

- The Gulf of Mexico is becoming one of the most interesting deepwater regions.
- Recent discoveries in Brazil in deposits beneath salt layers are a major change for the country’s offshore industry.
- East Africa is becoming a significant area for the offshore industry, with major discoveries in Mozambique and Tanzania.

Source: Arthur D. Little, 2016
Rystad Energy estimates that crude oil reserves from the offshore zones to about 830 bn boe, out of which approximately 70% have not yet been explored (Chart 2). So far, only 75 bn boe (i.e. under 10%) have been produced and another 67 bn boe have been developed. Considerable investments and efforts are needed for the exploration and development of the estimated reserves.

In the Rystad (2018a) ranking of the five greatest investments in the offshore fields between 2010 and 2018, Kashagan – Phase 1 (Kazakhstan) is first, with a capital expenditure of $30 bn, followed by Hebron (Canada) with $11.5 bn, Johan Sverdrup – Phase 1 (Norway) with $10.5 bn, Arkutun-Dagi (Russia) with $9 bn and Manifa – redevelopment (Saudi Arabia) with $8.6 bn. The same analysis indicates that the global average cost for the offshore extraction of one oil barrel is $6.4.

It is not uncommon for the development of a single project to cost $8-10 bn. In the Petrobras business plan for the development of the Santos Basin, investments of $225 bn have been foreseen. The Tupi deposit alone needs a financing estimated at $7 bn.

Among the large regional basins of the world, the largest offshore investments from 2010 to 2018 were made, according to Rystad (2018a), in the Asia-Australia-Russia region ($374 bn), followed by Northern Europe (the Northern Seas, the Norway Sea and the Barents Sea) with $217 bn, the Middle East ($198 bn), North America ($133 bn), Africa ($88 bn) and South America ($49 bn).

Chart 2: Global inventory of crude oil and gas resources in deepwater offshore zones

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8 Bn barrels oil equivalent
9 Fitzsimmons, Matthew (2018), How Norwegian Shelf Costs Stack Up in International Waters, Rystad Energy
10 Fixed offshore facilities; over 50% of the costs are related to technical engineering, procurement, constructions and installations (EPCI) expenses.
Increase of Costs for Deepwater Offshore Projects

Investments in the sector go to where the opportunities are; thus, from an estimated total investment of over $7,000 bn for the exploration and production sector over 2011-2020, 40% will be assigned to offshore explorations and exploitations, 18% out of which will be assigned to deepwater zones (Chart 3), respectively an average of $60-70 bn a year.

Chart 3: Global investments in deepwater offshore projects over 2011-2020

Investments in worldwide deepwater projects

This is also reflected in the evolution of the number of exploration and development wells drilled in deepwater zones which, over the past decade, has recorded an average annual growth rate of 8%. However, the drop in crude oil quotations between 2014 and 2017 has led to the visible deceleration of offshore investments, reaching the 2009 level. According to Wood Mackenzie (2015), the largest oil companies have suspended investment projects estimated to no less than $200 bn, in an effort to protect the investors’ dividends. More than half of them are deepwater projects, including in the Gulf of Mexico and West Africa.

A recent analysis carried out by Rystad Energy (2018b) shows that a couple of years after the offshore investment decline, the cyclic evolution of the market points to a returning growth tendency as of 2018 (Chart 4).

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The exploration and development activities in deep waters involve great investments. While an exploration well in the mature onshore zone costs between 5 to 10 million dollars, it may reach $100-180 million in the frontier offshore area, at a time when the probability of success is of about 20-25% – in other words, three or four out of five drilled exploration wells are dry or hit resources that lack economic viability.

A factor of cost increase of deepwater exploration wells (about 50%) was the tightening of the regulatory framework after the accident on the BP Deepwater Horizon platform in 2010 (Chart 5).

Some exploration wells cost over $250 million. Such an example is Pitanga, drilled by BP in the Brazilian waters, which was abandoned after engulfing a total of $850 million, according to the company’s 2014 annual report. The costs increase of exploration wells is part of a general trend of increasing barrel discovery costs, with an annual rate of 11% between 1999 and 2013 (Chart 6)\textsuperscript{12}.

Very expensive machinery, platforms, equipment and ships are used in the deepwater zones. An autonomous ship that can drill up to 15,000m below the sea level up to the deposit can cost around $800 million and is leased for $700,000/day. There is a leasing market for machinery, platforms and drilling vessels in the offshore, which until recently was a tight one, with high demand and limited offer.

\textsuperscript{12} Strachan, Gavin (2014), Deepwater drilling, a macroeconomic view, 2014
The growing investment need for offshore operations is illustrated in Chart 7, through the comparative analysis of expenses incurred by three supermajors: ExxonMobil, Shell and Chevron. It has been observed that growing investments are required, even if only to maintain the level of production. IOC are very active in deepwater offshore operations, as they seek to maintain their production and to replace reserves.


Source: Strachan, 2014
Life Cycle of a Crude Oil And Natural Gas Exploitation Project and Sector Investments Features

What distinguishes oil and gas exploitation projects in general and the offshore ones in particular is the long investment duration, their very high value and the significant risks. Chart 8 presents the lifecycle of a deepwater offshore project lasting up to 30-40 years, divided into three main phases: exploration, development and production.

In the exploration phase, which can last 4-5 years, an investor undertakes costs related to geological and seismic studies, exploration activity, appraisal wells, acquisition of exploitation rights etc. For example, Royal Dutch Shell started taking an interest in the potential of oil and gas from of Arctic region in the late 1980s. Back then, a couple of wells were drilled, which identified gas reserves in the Burger perimeter, in the open Sea of Alaska, but which at the time did not present economic viability. The company re-evaluated the situation in the early 2000s and reached the conclusion that oil might be discovered in that region, so in 2008 it purchased several exploration licences in the same perimeters. After another seven years, Shell had not yet drilled a single production well, but the company had already invested $7 bn in this project. Eventually, Shell gave up on the Arctic operations.

Chart 8: Life cycle of an oil and gas project

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Crooks, Ed (2015), Shell ready to seize its Arctic drilling chance, in Financial Times, 26 May
If an investment decision is made after analysis of the seismic and geological data and the results of the exploration wells, the development phase begins, which lasts for 2 to 3 years, during which a very high cost investment plan is implemented. On average, for 7-8 years from the beginning of a deepwater oil and gas exploitation project, it registers only cash outflows and zero cash inflows.

For example, the Ichthys project of West Australia, in the Timor Sea, operated by the Japanese company INPEX, is currently exploiting one of the largest natural gas deposits discovered in that part of the world, at an estimated development budget of $34 bn. It aims to integrate three large offshore gas fields, to build an onshore processing facility for liquefaction and to connect them to a 900-kilometre long pipeline.

Another example is the Kashagan project, in the Caspian exclusive economic zone of Kazakhstan. This supergiant field is estimated to contain 10 bn recoverable barrels (from an estimated total of 38 bn) and no less than 1 trillion m$^3$ of natural gas. It was discovered in 2000 and was developed by a consortium comprised of KazMunayGas, Eni, Shell, Total, ExxonMobil, the Chinese company CNPC and the Japanese company INPEX. The total estimated costs for the project are over $50 bn, reaching even $100 bn – two or three time more than the initial estimates. The field started producing in 2013 (although the initial expectations were for 2005), but the operations were stopped after just a month, because of gas leaks. It turned out that the entire 200-km offshore pipeline segment had micro-fissures caused by the high content of sulphides associated with the extracted gas, thus it had to be entirely replaced. Production was only resumed in October 2016 at a level of 90,000 barrels a day, exceeding 300,000 barrels a day in 2018 and still targeting 370,000 barrels a day.

As Chart 9 shows, with regard to the deepwater projects, the production begins, on average, after some seven years from the project initiation, unlike the onshore and shallow water offshore projects. With the production phase, revenues start to flow as well, so the first profits are generated roughly 10 years after the project initiation – 2-3 years after the production start. In the production phase there are other cash outflows represented by taxes, royalties, fees, as well as operational expenses. When the project’s economic viability limit is reached, new costs emerge, related to the field’s shutdown or abandonment and the rehabilitation or restoration of the area, including dismantling of infrastructure.

After the approval of the investment plan, the financial commitment becomes virtually irrevocable. Once the investment is approved, the investor is captive, so changing the taxation has direct effects – this is why investors demand stabilization clauses in the contracts, as detailed below.

The projects pertaining to this sector, besides requiring significant investment with long payback periods, are carried out under multiple risk conditions. Prior to the detailed risk analysis, several general comments on the link between the total risk and the profitability demanded by the investors are useful.

As Chart 9 shows, with regard to the deepwater projects, the production begins, on average, after seven years from the project initiation, unlike the onshore and shallow water offshore projects. With the production phase, revenues start to flow as well, so the first profits are generated roughly 10 years after the project initiation – 2-3 years after the production start. In the production phase there are other cash outflows represented by taxes, royalties, fees, as well as operational expenses. When the project’s economic viability limit is reached, new costs emerge, related to the field’s shutdown or abandonment and the rehabilitation or restoration of the area, including dismantling of infrastructure.

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14 The economic viability limit of the project is reached when the exploitation net cash flows become negative.
The investors assess the risk and the expected return of the project. The greater the risk, the higher the expected return. In order to diversify the risks and to reduce the total risk, the O&G companies build diversified project portfolios. From this point of view, the sector resembles the pharmaceutical, aerospace and defence industries, in which long-term large and risky bets are also made, either on molecules or a new type of transport or fighter aircraft. Not all projects succeed, but due to the fact that each company has a diversified portfolio, the ones that do succeed need to compensate for the lost bets. In any event, the investment is only recovered after many years.

Taking into consideration the total risk, the investors expect an IRR for deepwater offshore projects of over 15% and it can reach up to 20%. Taking into account the impact of the failed projects on the financial results, there results an average IRR to the IOC capital of over 12% on the long-run, in line with the investors’ expectations in a sector of high risk, and not significantly different from the NOCs’ return rate, which generally exploit much richer and easier to access deposits.

Risks of Deepwater Offshore Projects

One of the determining factors of the investment decision in O&G projects is the distribution of risk between the license holder (i.e. the investing company or consortium of companies) and the resource owner (most often, the host state). The risks have an impact on the operation costs and on the projects’ profitability. The O&G exploration and production operations are, inherently, risky and capital-intensive, and all of these are more pronounced in the case of offshore operations. 7-10 years may pass between making the capital investments and obtaining the first revenues from selling the extracted resources.

The table below presents the most significant risks of the deepwater offshore O&G sector, which are components of the total risk. Each of them is shortly presented below. Some can be influenced by the investor, others depend on the policies and regulations of the host state, while others do not depend on either party, being expressions of global phenomena.

Figure 1: Main risks in the crude oil and natural gas offshore sector

- Resource Uncertainty
- Taxation
- Management
- Regulation
- Price
- Environment
- Technology
- Terrorism
- Infrastructure
- Reputation
- Weather forecast
- Geopolitics
Despite the technological progress, the probability of drilling a successful well is between 20-25%, which can lead to costly failures – or, if looked at differently, to useful experiences. BP mentions in the 2014 report no less than 12 examples of unsuccessful wells. The largest of them is the already mentioned Pitanga well in Brazil, other examples being Algeria ($524 bn), India ($139 bn), Gulf of Mexico ($500 bn), China ($112 bn), Angola ($110 bn) and Morocco ($83 bn). Another example is Statoil, the Norwegian national oil company, which drilled three wells in the Arctic region in 2014 and all of them were dry.

The challenges related to the lack of necessary infrastructure and logistics services can be significant. They are essential for bringing oil and gas to the market. There are zones in the world with already developed infrastructure (pipelines in the first place), such as the Gulf of Mexico and the Northern Sea. However, in the new frontier areas – the mid-Atlantic, the Arctic region, East Africa or the Black Sea region – there is scant already developed infrastructure. For example, in the middle of the Atlantic, a pipeline network cannot be built. In such cases, offshore storage, processing and transport capacities will be needed. Figure 2 presents a typical production system in the deepwater offshore zones.

If for crude oil there are oil tanks to take over the output and transport it to onshore storage facilities, deepwater natural gas cannot be connected to the mainland through pipelines, so that offshore liquefying facilities are needed, which is much costlier.

Figure 2: Structure of an offshore drilling ship’s exploitation pipelines
Technology

The technological evolution in the O&G sector is both a risk and an opportunity. It is a risk, because the recent progress confirms that, for instance, renewable energy sources supported by high-performance batteries can become a strong competitor in the energy mix, since their costs decrease in time. At the same time, the extraction cost of finite resources, such as oil and gas, is on an upward trend. Technology can also be a competitor, because it generates replacements. At the same time, technology can well be an entrance barrier. Whoever controls it can keep the competitors at bay, at least for a while. With the exception of Petrobras, the large NECs do not have the necessary technology for deepwater offshore zones.

Finally, technology can also be a facilitator, an opportunity. The way in which deepwater offshore zones are currently explored was unconceivable 20 years ago. The vessels, drilling platforms, as well as the processing technology have made enormous progress in the recent decades, allowing the development of resources which in the past were inaccessible or uneconomical.

In order to understand the technological challenges, it should be mentioned that some fields are at a total depth of 9,000m below the sea level (in waters 2000m deep and 7,000m underneath the sea floor). The equipment located on the sea floor must operate at a pressure of 200 atm for some 20 years – for comparison, state-of-the-art nuclear submarines do not descend to depths greater than 500 m.

For all the progress, technology may still face problems. For example, the exploration done by Shell in the Arctic Ocean were shut down twice as a consequence of material breakdown. The engine of the drilling ship Noble Discoverer failed and the cables with which the Kulluk platform was being towed broke and it stranded, eventually being abandoned.15

Another example of technological risk is illustrated by the Chevron project in the Gulf of Mexico, dubbed Big Foot. The field is located 225 miles south of New Orleans, in waters about 1,600m deep and it should have produced 75,000 barrels of crude oil and 675,000 m3/day. The production platform, with a height of 130m, was going to be anchored to the sea floor through 16 tendons (steel tubes with a diameter between 61 and 81 cm). On the June 1, 2015, during the connection manoeuvres to the body of the platform, six of the tendons lost their buoyant boxes and sunk. This incident significantly affected the production calendar and generated high additional costs for Chevron,16 as well as a delay in production until 2018.

Additionally, the importance of the IT systems needed to process and interpret the seismic and geological data, as well as the drilling results, is steadily increasing. BP, for example, developed in Houston, Texas, a data centre with a 2.2 petaflops data processing capability (2.200 trillion calculations per second), given that the company’s computational power requirement increased by 20,000 times compared to 1999.17

Commercial Risk and Fluctuations in Petroleum Quotations

It has already been noticed that the oil price drop of late 2014 has led to the cancellation or delay of many deepwater offshore projects. According to a Bernstein analysis, in 2014 only 39 offshore projects were launched (similar to what happened over 2008-2009, during the peak of the global financial crisis, when the Brent oil benchmark had collapsed to about $40 a barrel from its historic peak of $147 a barrel in July 2008), compared with an average of $59 a barrel over 2011-2013.

15 Crooks, Ed (2015), Financial Times, Shell ready to seize its Arctic drilling chance, 26th of May
16 Reuters (2015), Chevron says production at Big Foot field delayed, 2nd of June
17 PwC (2013), Driving Value in Upstream Oil and Gas
Under the new market conditions, the selectivity of projects is essential, and not necessarily the execution speed. With only one project, many companies risk an important part of their value and even their existence. That is why the careful selection of investment projects is critical. Not only the volume of discoveries is important, but also their quality, which varies a lot based on the type of fields. For example, in the Canadian province Alberta, 13 deposits generate 13 different types of oil, their value being different depending on their quality.18

Project Management

Despite the technological development and advanced management, many of the exploration and production projects register delays and cost overruns on an average of 20%. Projects that seemed to have potential were shut down.

Such an example is Shtockman in the Russian Arctic region, which had the following associates: Gazprom, Statoil and the French from Total. It foresaw the exploitation of a field located 600 km north of the Kola peninsula, with an estimated potential of 3,800 bcm natural gas and 37 million tons (mt) of gas condensate. Discovered since 1988, the development of the project only begun in 2005, when an agreement was signed between Russia and Norway. However, for a number of reasons – disagreements among partners, cost overruns – the project was shut down in 2012.

Environmental Risks

The 2010 accident that took place on the Deepwater Horizon platform operated by BP in the Gulf of Mexico has become a classic example. The company has paid so far compensations of $60 bn and the disputes have not been settled yet. This has also been reflected in BP’s market value, which collapsed after the accident, before gradually recovering in the recent years.

Reputational Risk

The environmental accidents, the controversies related to the sharing of profits among governments, investors and communities, the protests of certain social groups against big business may have, in the context of global communication (amplified in recent years by disinformation actions propagated mainly through social networks) a significant impact on the reputation of large companies pertaining to this sector.

18 Egbert, Darryl (2015), Commercialization Challenges for Offshore Resources, ExxonMobil
The petroleum sector represents a traditional target for governments in search of budgetary revenues. The tax risk increases especially after an investment becomes irrevocable and the investor can no longer step down. Changing the fiscal terms during the development of a project can significantly affect the profitability parameters or even the project’s viability. That is why, from the industry’s standpoint, it is essential to adopt stabilization and predictability clauses before the beginning of the projects, as detailed in the following section.

Fiscal terms must reflect the profile of the fields and the difficulties of extracting and marketing the reserves. It is not adequate to impose the same fiscal terms for onshore and deepwater offshore exploitations, to rich and marginal fields, or to conventional and unconventional deposits.

It has been noticed that at a global level, in areas with a low total risk, a higher level of taxation is applied, whilst in high risk areas, such as the deepwater offshore deposits, taxation is generally lower (Chart 10).

The government’s share of the returns made from O&G fields varies between 15 and 95%, depending on numerous factors. The diversity of tax approaches, in close relation to the risk profile, is so large that a single global formula cannot be established. Some states adopt a moderate taxation to attract investments, especially in the areas where significant breakthroughs have not yet been recorded (Ireland, Morocco, the Arctic region). The government’s share is in the higher zone of the interval in the case of easy to exploit fields, with a high yield and profitability and for which the investors have already recovered their investments. Additionally, there is a trend to increase the percentage of revenue tax in the total taxation of companies in this sector, to the detriment of royalties.

Chart 10: Tax system and taxation level must be correlated to the total risk’s profile
Regulation Risks

Grave accidents such as the one of Deepwater Horizon have prompted changes to the regulatory framework, which is becoming increasingly complex and constraining. Thus, offshore operations have become safer, however, incurring higher costs.

Weather Risk

The weather risk is high in the Arctic region, where drillings can be carried out only 3-4 months a year during summer. The same goes for the Gulf of Mexico, known for its frequent hurricanes, South-East Asia, West Australia, the middle of the Atlantic, and even the Black Sea, where violent storms have been registered. A major weather event could lead to the destruction of facilities and infrastructure, thus causing enormous environmental problems.

Terrorism Risk

Some deepwater offshore exploitation perimeters are in the vicinity of terrorist organizations’ operation areas – for example, insurgent groups in the Niger Delta or pirates in the Horn of Africa.
Importance of Stability for Investments Made in the Petroleum Sector. Brief Comparisons Regarding Taxation

Petroleum Tax Regime and Stabilization Clauses

In general, the investors manage the risks related to geology, technology and know–how, financing, overall costs of operations, as well as to the commercial risk, but not the political and regulation risks, which also include the tax risks. The latter depend mainly on the behaviour of the host states. The risks associated with an unstable and unpredictable tax environment have a major impact on the general risk profile of the investment and of the anticipated returns.

The lower the regulation risk in general and the tax one in particular the larger the share of revenues generated by petroleum activities. When governments resort to changing the fiscal terms to increase their share of the revenues generated by the extraction of natural resources, the unintended effect is limiting the investors’ economic activity (in extreme cases, even their withdrawal), with the effect that the taxable revenues generated by them drop or disappear completely. The negative impact on investments is even greater when these tax regime changes do not only affect the future contracts, but the projects in progress as well.

As stated in the UN handbook regarding the extractive industries taxation\(^{19}\) (2017: 239),

“Overall, countries that are perceived to have lower levels of risk (technical, political, oeconomic) will be able to command higher levels of government take – i.e. higher rent takes, or other fees and obligations. Countries perceived to have higher levels of risk will need to design their fiscal regimes to be more attractive to incentivise companies to put capital at risk.”

But this does not mean that governments do not have the tendency to revise the petroleum fiscal framework. Indeed, as noticed by Mansour and Nakhle (2016)\(^{20}\), in a study of Oxford Institute for Energy Studies,

“Governments keep tax regimes under almost continual review; the dynamics of what constitutes a ‘fair share’ of the resource rent are fundamentally unstable given volatility in oil and gas prices, unpredictable geology and global competition for scarce capital and know how.”

The states’ interest to maximize their “share,” the governments’ budgetary needs, the tendencies on the international markets, or a simple government change can trigger initiatives to revise the tax regime. The revision can take place already during the geological exploration phase, before the development of the fields.

As noted in the UN Handbook (2017, 239), in the early phase, after opening the exploration perimeters, the governments tend to stimulate investments in exploration, characterized as high risk, offering advantageous fiscal terms for the investors. But once the hydrocarbon discovery has taken place and the reserves have been proved reserves, and after the investor allocates large sums that can no longer be withdrawn, the governments increases the taxation. Such situations are called obsolescence bargain in literature – i.e. a bargain that has lost its actuality as the investors has diminished their bargaining power.

Factors Triggering Petroleum Tax Regime’s Instability

Let us analyse in more detail the factors that trigger the instability of petroleum tax regimes. The increasing oil price volatility on the international markets, respectively the regional ones, in the case of natural

\(^{19}\) United Nations (2017), Handbook on Extractive Industries Taxation

gas, is a good predictor for revision initiatives in the upstream tax regime by the host states. According to the World Bank data (2009)\(^1\), from 1990 to 2009 (as the average annual Brent barrel price dropped from $23.70 a barrel in 1990 to $12.74 a barrel in 1998, to rise up to the peak of $96.94 a barrel in 2008) more than 30 countries have revised their petroleum contracts or their entire tax regime. Between 2000 and 2008, a period of continuous oil price increase, countries like Angola, Argentina, China, Ecuador, India, Kazakhstan, Libya, Nigeria, but also Alaska in the U.S., increased the level of taxation applied to the oil companies.

The main reason is based on the fact that a tax regime established when the average annual price of a barrel is $30-40 differs structurally from a tax regime built around price values of $80-90 a barrel, from the standpoint of the government’s share.\(^2\) Under such changes of the oil market, the governments quickly come to regret the exaggerated generosity offered through the tax regime to the industry. Thus, using the higher bargaining power obtained from increased prices, they force changes on the fiscal terms. On the other hand, when the oil prices collapse, the trend is exactly the opposite: the oil companies, whose investments the governments need so much, get higher bargaining power, so that the fiscal terms changes occur in their favour – although, as Mansour and Nakhle (2017) notice, the response to price drops is slower and less systematic than in the case of price increases.

Such an example is the British government’s decision, in 2015, against the backdrop of the oil price fall at the end of 2014, to offer the oil and gas industry a £1.5 bn fiscal aid in the form of tax relief and additional measures in support of the exploration activities in the continental shelf of Great Britain. Another example of revision, driven primarily by the need to attract investment, is Algeria which, following unsuccessful tenders for oil and gas perimeters in 2005 and 2008, decided in 2013 to offer considerably more attractive fiscal terms, through a new law.

Since international practice is, with few exceptions, to include in the petroleum agreements (i.e. concession contracts) stabilization clauses designed to ensure during the agreement the application of the fiscal framework in force at the time when it was signed, the impromptu and unilateral changes to the tax legislation have led to the opening of numerous international arbitration actions. As shown below in Chart 11, there is a clear correlation between the increased number of arbitration cases in the oil and gas sector and the increase in the oil price.

Another recurring situation of revising the fiscal framework takes place in the early stages of the life cycle of a field that the resource owner decides to explore and develop by attracting international investors capable of providing the needed technology and capital. In order to attract investors, governments offer attractive tax conditions.

**Chart 11: Brent oil price and international arbitration cases in the oil and gas sector**

\(^{1}\) World Bank (2009), Global Economic Prospects: Commodities at Crossroads, Washington, DC: World Bank

\(^{2}\) A notable exception are those flexible fiscal frameworks that include wide variations in the price factor, agreed between the state and the investors, of sliding scale type, as in the case of Alberta, Canada’s most important oil province.
However, as the exploration operations confirm the existence of significant commercial hydrocarbon resources, governments tend, as owners of these reserves to considerably increase their share, through amending or even completely changing the law. On one hand, this illustrates what was presented above as the problem of obsolescence, as a direct expression of the increased bargaining power of the government. On the other hand, however, it is related to a lack of knowledge, prior to the execution of extensive exploration works, of the real geological and commercial potential of the fields in a specific basin.

This latter case is illustrated in the evolution of the Israeli fiscal framework: in 1999, the American company Noble Energy discovered the Noa deposit in the territorial waters of Israel, in the Eastern Mediterranean Sea. In the following years, the Mari-B field were discovered in 2000, Dalit and Tamar in 2009, Leviathan in 2010 and Tanin in 2011, confirming the huge potential of the Levantine Basin. But in 2000, the Israeli National Infrastructure Ministry did freeze all offshore operations, giving the government time to amend the oil and gas tax regime. This happened six years later, with an increased government share. But the new regulations were applied only to the concessions made after the entry into force of the new law; a transitional, less burdening tax regime was applied to the existing concessions.

Other factors that sometimes lead to a review of fiscal framework are the change of government (especially when it is accompanied by deeper ideological shifts, given that governments are usually critical of their governing predecessors), respectively the deterioration of the public finance situation, that prompts some governments to resort to the introduction of so-called Robin Hood taxes, which additionally tax the revenue obtained from oil and gas operations. But, besides the fact that such taxes sometimes prove to be unconstitutional, in the international practice the application of a windfall additional tax on “extraordinary profits” is for a limited time period of up to 2-3 years; the undetermined extension or even rendering such taxes permanent by law is unusual and creates distortions in the competitive environment.

Fiscal stability clauses

Under these conditions, it is understandable that the investors are searching for mechanisms to diminish and manage the fiscal risk. As previously mentioned, the fiscal stability clauses included in the petroleum agreements (which have the characteristic of long-term contracts between the state owning the resources and the concession title holder) are meant to protect investors from a possible discretionary exercise of authority by the sovereign state through nationalization, expropriation, obsolescence, Robin Hood taxes, etc. Such a tool of fiscal risk mitigation is needed not only by investors, but by financiers as well, as fiscal stability is a defining condition of a project’s bankability. On the other hand, the governments accept stabilization clauses in order to attract investments and to increase the competitiveness of their oil and gas projects on the international market.

It must be mentioned that, in a certain sense, the activation of a fiscal stability clause is a “nuclear option,” being a last resort to which the investors cannot turn in international arbitration instances without gravely deteriorating the relations with the host government. That is why, in situations where the states initiate changes in the oil and gas fiscal framework, negotiations leading to a new compromise formula, acceptable for both parties, are preferred.

Moreover, the modern stabilization clauses have evolved from the initial approach of freezing the tax terms in force at the moment the concession agreement was signed to an approach based on ensuring the “economic balance” of the contractual relationship between the concession holder and the resource owner. In other words, the focus shifted to the insertion of some compensation and balancing elements in the context of changing the fiscal framework, so as to maintain the defining economic conditions of the contract.

Despite all of these, as Chart 13 shows above, the cases in which stabilization clauses are activated in international arbitration courts have become more frequent. Invariably, this means severe financial costs, at least for one party, as well as reputational costs that can be very difficult to recover.

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23 In February 2015, the Constitutional Court of Italy declared unconstitutional the Robin Hood tax of 6.5% added on top of the usual profit tax, introduced in 2008 – first imposed on oil companies and then, starting in 2011, on renewable energy producers as well.
The Black Sea covers an area of about 415,000 km² (1,150 km in the east-west direction and 600 km in the north-south direction), it is bordered by six countries (Bulgaria, Romania, Ukraine, Russia, Georgia and Turkey) and communicates with the Mediterranean Sea through the Bosphorus and Dardanelles Strait. From a geological perspective, it is composed of two sub-basins, an eastern and a western one, separated by a central rift. The geological potential of natural gas resources is estimated to be greater in the western side, whilst oil is dominant in the eastern sub-basin.

From a petrological perspective, the Black Sea is considered by many to potentially be a new Northern Sea, the most important European region from an energy standpoint. However, this potential is mostly theoretical, with the geological exploration still being at an early stage (about 100 drilled wells). Important discoveries have only been made so far in the Romanian waters. All Black Sea coastal states have ongoing exploration projects, more advanced being the ones from Romania, Turkey and, to a certain extent, Bulgaria (Map 2).

Map 2: Offshore exploration projects in the Black Sea

Source: Schlumberger, 2015
The exploration projects in the Black Sea feature almost all of the deepwater general risks, but also some other specific risks:

- The success rate of the exploration wells is about 20-25% in Romania. It has been, however, 0% in the case of Turkey and Bulgaria. The costs of drilling a well in deep waters varies between $150 and $250 million.

- The commercial risk is significant, based on the poor connection of the Black Sea Basin to the western European markets.

- The infrastructure and logistics are, for now, poorly developed (unlike the Northern Sea or the Gulf of Mexico), both offshore and onshore;

- The know-how and project management resources are still very scarce, despite the efforts made by countries like Romania and Turkey;

- The geopolitical risk is on an upward trend, as a result of the political and military events in Crimea and Eastern Ukraine, and with Turkey in antagonistic relations with its Western allies. Crimea is currently strongly militarized, with advanced A2/AD (anti-access area denial) capabilities. NATO ships patrol the waters of the Black Sea and NATO fighter aircrafts oversee the airspace of its southeast European extremity. This unprecedented increase in military capabilities in the Black Sea Basin is inevitably reflected in the geopolitical risk perception of the oil and gas license holders and potential investors;

- The fiscal risk is high and continues to grow. It is manifested through a lack of stability and predictability, tax changes being applied retroactively and without minimal consultation;

- The environmental risk is appreciable, as the Black Sea is being swept by violent storms. The fields are located at a great distance from the shore, rendering a potential intervention extremely difficult, in the absence of specialized equipment and experience;

- The legal and regulatory risks is rising, accentuated by the Crimea annexation and the de facto expansion of Russia’s exclusive economic zone.

Besides these, there are also other specific risks for the Black Sea:

- It is a nearly enclosed sea, difficult to access through Bosphorus. The minimum depth of the Bosphorus Strait is less than 50m and the bridges connecting Europe to Asia at Istanbul are 64m above the water. That means that the drilling platforms must be dismantled in order for them to be crossed over Bosphorus and subsequently rebuilt, which significantly increased costs (Photo 1);

- Because little exploitation was carried out, there is not enough information on the topography of the Black Sea floor, which can complicate the pipeline route. Additionally, the sea floor is unstable;

- Hydrogen sulphide is found at depths below 200m, having a corrosion effect on the pipelines and equipment. The equipment capable to operate in such an environment is significantly more expensive. Moreover, at depths greater than 500-600m, the sea water is saturated with methane;

- Large quantities of methane hydrate lie on the sea floor, which can be dangerous if they reach the surface, posing a risk of fire or reducing the ships’ buoyancy;

- In the region, there are few petroleum services companies with the capacity required for deepwater offshore works.
The total risk resulting from the aggregation of the specific and general aspects outlined above is high in the case of the Black Sea. This, on the one hand, makes the exploration activity less intense than expected, and on the other hand renders the returns expected by the investors higher, in order to compensate for the risks.

Thus, despite the region’s high hydrocarbon potential, the exploration activity is less intense than anticipated, especially because of the risks mentioned above. According to Wood Mackenzie (2017), the largest volumes of hydrocarbons have been discovered in the north-east of the Black Sea, along the coast of the Russian Federation, followed by the exclusive economic zone around the Crimean Peninsula.

But large resource volumes do not necessarily mean high value, because the commercial value depends crucially on resource accessibility – depth, fragmentation, etc. Indeed, the commercial value of a field depends also on factors that have to do with the states’ policies, regulations and behaviour (stability of the political and regulatory environment, liberalization of the gas markets, in particular, and of energy markets in general, a certain level of infrastructure development, but also access to the perimeters, etc.), as well as uncontrollable regional and global factors, such as geopolitics or international markets.

In terms of value, six out of the first 10 deposits in the Black Sea are located in Romania’s territorial waters and exclusive economic zone. The Istria block, located in the shallow waters of the Romanian Black Sea, is the leader, followed by Neptun Deep, Midia and Pelican.

**Turkey, Bulgaria, Ukraine**

**Turkey.** Although Turkey’s economy is currently affected by a financial crisis, it remains the most important regional energy consumer, with an annual bill of $60 bn in energy imports of various types. In order to satisfy its thirst for resources and strengthen energy security (aiming to ensure energy independence by 2023), Turkey has begun to intensively explore both the conventional onshore and the deepwater offshore zones in the Mediterranean and the Black Sea.

Significant reserves have been identified in the Mediterranean, but the deposits are located in an area disputed with Cyprus. Against this background, Turkey focused on the perimeters of its Black Sea’s exclusive economic zone, estimated by TPAO, the Turkish national oil company, to have reserves of 10 bn boe and 1,500 bcm.

For the exploration of the Black Sea perimeters, Turkey signed three deals with Chevron, ExxonMobil and Petrobras over 2009-2010. Each agreement involved investments of about $400-500 million, respectively the drilling of two wells each. The results of these explorations were modest, all six exploration wells being dry.

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24 Wood Mackenzie (2017), The Black Sea: Unlocking Its Potential, April
In 2010, Chevron announced its temporary withdrawal from Turkey and allegedly paid a $100 million penalty clause. In 2011, ExxonMobil also abandoned two exploration perimeters. Petrobras also shut down the exploration operations in the Turkish exclusive economic zone.

Despite these failures, Turkey never abandoned its exploration efforts and TPAO signed an exploration contract with Shell for the Black Sea’s western area. Shell signed up to investments of about $200 million for drilling a well. Ankara continues its exploration effort and this will focus on the perimeters of the Turkish exclusive economic zone, in the vicinity of the Romanian Neptun block, where ExxonMobil and OMV Petrom identified natural gas reserves. More recently, Turkey has acquired two seismic exploration and deepwater (13,000m) drilling ships to pursue works of identifying natural gas reserves in the Black Sea.

Turkey is a good example of the risks and uncertainties associated with exploration activities in the deep waters of the Black Sea and unfortunately confirms the statistics. Great financial efforts have been made, but to no avail so far.

Bulgaria. The exploration activities in the exclusive economic zone of Bulgaria started in the mid 1980s, when a total of 30 wells were drilled. Six finds were announced, but none of them was developed. In the early 1990s, Texaco drilled in the shallow Bulgarian waters. In 1998, the company waived its titleholder rights. In 2008, Melrose (which later became Petroceltic) drilled in the shallow waters two wells that were later put in production at low flow rates.

Production did virtually cease in 2014, with a dramatic impact on the country’s natural gas production. The mid 2000s marked the entry in the Bulgarian offshore of two supermajors, Shell and Total (in partnership with Repsol, respectively, OMV). The first deepwater well was drilled in 2016 by the French company. Total announced that the drilling was successful, without offering additional information. In 2017, Shell finalized the 3D seismic exploration of a 5400 km² area in the 1-14 Han Kubrat perimeter, out of which two thirds are located in deep waters.

Ukraine. Ukraine’s potential of natural gas resources from the exclusive economic zone was deemed to be significant and capable of contributing to the country’s energy independence. To capitalize on gas resources, Kiev signed agreements or started negotiations with some supermajors. Thus, in 2012-13, a production sharing agreement (PSA) was signed with ENI, Shell and Chevron. Between 2012 and 2014, Ukraine negotiated the development of the Skifska perimeter (estimated at 5 bcm/year) with a consortium led by ExxonMobil, which included Shell and OMV Petrom.

Other agreements were under negotiation at the time Crimea was annexed by the Russian Federation. In the public debate over Crimea’s annexation, the emphasis was mainly on military and strategic aspects. But there is also a major energy stake in Russia’s de facto takeover of Crimea’s exclusive economic zone, which tripled the Russian perimeters’ area. This happened in the context in which Moscow had tried to minimize the relevance of the resources in question. Russia also took over two state-of-the-art Ukrainian exploration ships. The sanctions regime imposed on Moscow after the annexation of Crimea has led to mothballed projects and significant losses for the investors. In addition, by de facto expansion of the Russia’s exclusive economic zone, this is now adjacent to Romanian and Turkish perimeters, increasing the risk of international legal disputes.
Romania

A part of the exploration activities that took place in recent years resulted in discoveries, which however have not yet been declared commercial. The most important of them are the following:

- In March 2012, OMV Petrom and ExxonMobil announced that at the Domino 1 well in the Neptun Deep perimeter, recoverable resources of natural gas were discovered estimated at 42 to 84 bcm;

- In October 2015, Lukoil, PanAtlantic and Romgaz announced the discovery of resources that, based on the seismic data and on evidence obtained during the drilling operations, are estimated at about 30 bcm;

- Two significant discoveries were made in the Midia perimeter: Doina in 1995 and Ana in 2008, which amount to recoverable resources of 9.5 bcm.

On the other hand, both in these perimeters and in others, a significant number of unsuccessful wells have been drilled.

Additional Taxation Proposal In The Offshore Draft Law (July 2018)

Investments in Romania’s offshore sector were made on the basis of the stability provisions included in the Petroleum Law No. 134/1995, Petroleum Law No. 238/2004, OUG No. 160/1999 (approved through Law No. 399/2001), as well as on the basis of stabilization clauses mentioned in individual petroleum agreements.

The recent legislative proposal made by Romania’s Parliament regarding the offshore oil and gas activity (Offshore Law), sent back for reanalysis by the President on August 2, brought a significant level of regulatory unpredictability. From a taxation perspective, a proposal was made to introduce, besides the royalties established through the Petroleum Law No. 238/2004, a progressive tax on revenue, as shown in Table 1.

Additionally, the legislative proposal provides deductibility of investments within a limit of 60% of the “extra” revenue resulting from the sale of natural in the different price ranges indicated. However, several deficiencies in the determination mechanism of the deduction and tax base from this draft law are disincentivising investments:

- Only investments made during the month in which the additional revenue is earned can be deducted. Yet in offshore O&G projects, investments are made mainly before the start of production, which makes it impossible to deduct them, as the draft law does not deferment of investments that cannot be deducted in periods when there is no additional revenue. However, such an investment deferment mechanism is common in the international practice (e.g. the UK, Norway, the Netherlands) and is also provided for in the Government Ordinance 7/2013 on the taxation of additional revenues applicable to onshore concession holders;

- Investments cannot be deducted from additional revenues exceeding 85 Lei/MWh, the deduction being limited to additional revenues up to this level;

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Source: Energy Policy Group (EPG), 2018
• Investments made before the entry into force of the law, amounting to more than $2 bn only for exploration activities carried out over the last 10 years, cannot be deducted;

• Starting with the September 1, 2019 no inflation adjustment will be made for the lower threshold of determining taxable revenue (45.71 Lei/MWh), although the indexation is still applied to the higher price thresholds, thus leading to a tax base growth over time;

• Royalties are not deducted from the tax base, as provided in OG 7/2013 on the taxation of additional revenues, which applies to the onshore concession holders and as it is common in the international practice.

With such a change in the offshore fiscal framework, Romania would be propelled to the second position in terms of taxation level in the extended region of the Black Sea and Caspian Basin, after Azerbaijan (33% government share, 19% investor IRR), with a government share of 31% and a 22% investor IRR. Kazakhstan, Turkey, Ukraine and Bulgaria are the following in the ranking done by Wood Mackenzie (2018) for the extended Black Sea region (which includes the Caspian Basin). The government share in Bulgaria is 21% and IRR is 64%.

It is also noteworthy that the intention to substantially increase taxation occurs in the context in which the neighbouring countries raised their competitiveness through tax cuts for the offshore sector. Thus, Ukraine reduced the royalties, whilst Kazakhstan introduced an advantageous tax regime, based on revenue, for the deposits which have not yet been developed.

Moreover, this proposal was brought forward in the context of an already increased oil and gas taxation in the recent years in Romania. In February 2013, the government issued a decision (OG) No. 7/2013 which introduced a tax on the „supplementary” revenue resulting from the deregulation of natural gas prices. In 2017, that tax, which was supposed to be a transitory one, was made permanent by the Parliament, which also increased its maximum level to 80%.

Governmental Decision (OG) No. 6/2013 is also in force since 2013, by which a 0.5% tax was set on revenues resulting from the sale of crude and condensate. Together, they made Romania climb up the European Petroleum Taxation Ranking, as shown in the Deloitte Romania’s annualized study on similar royalties and taxes in the petroleum sector. (Table 2)
It has been noticed that, based on the significant drop of the oil price between 2014-2016, the European states continued the trend of lowering the average royalty rate and other taxes for the upstream petroleum sector – dropping from 9.8% in 2015 to 8.8% in 2016, while the actual taxation rate in Romania continued its ascending trajectory, going up from 16.9% in 2015 to 17.4% in 2016.

In 2017, the aggregate petroleum taxation dropped in Romania, based on the abrogation of the 1% tax on special constructions, applied to the gross book value of the oil and gas wells, pipelines, etc.

A differentiated onshore-offshore analysis of the actual level of taxation in 25 European jurisdictions that have been evaluated is also relevant. Thus, the level of onshore taxation in Romania is high in comparison with the European average. There are, however, two jurisdictions with a higher effective tax rate, both in 2015 and in 2016. On the other hand, even without taking into account an additional tax applicable to the offshore sector in Romania, the maximum royalty level of 13% applies in Romania to virtually all offshore gas production, due to the production thresholds which are not adapted to the offshore specifics. This represents the highest effective tax rate in 2016 compared to the European offshore jurisdictions (respectively, the second highest tax level in 2015, very close to the effective tax rate in Norway of 13.9%).

Under such circumstances, in order to maintain the taxation system’s competitiveness, a possible additional tax for the offshore sector would need to have a balance structure and level, and the royalty calculation formula must be adapted to the specifics of this sector.

The diversity of the risks presented above makes it difficult to identify an optimum fiscal approach, that would be universally applicable, regardless of the geological, political, geopolitical and regulatory circumstances of the different jurisdictions. However, a conclusion remains valid: the tangible measures to mitigate the aggregate risk allow both to obtain a larger government share and to ensure a sufficient payback for the investors.

### Table 2: Average rate of royalties and other similar petroleum taxes in Europe

<table>
<thead>
<tr>
<th>Region</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
</tr>
</thead>
<tbody>
<tr>
<td>Romania</td>
<td>15.0%</td>
<td>16.0%</td>
<td>17.4%</td>
<td>13.9%</td>
</tr>
<tr>
<td>The rest of Europe, except Groningen, Netherlands</td>
<td>9.1%</td>
<td>7.5%</td>
<td>6.9%</td>
<td>n/a</td>
</tr>
<tr>
<td>The rest of Europe</td>
<td>11.6%</td>
<td>9.8%</td>
<td>8.8%</td>
<td>n/a</td>
</tr>
</tbody>
</table>

Source: Deloitte Romania (2018)

29 The Groningen natural gas deposit, in the Netherlands, is the largest one in Europe, having a separate taxation regime.
Conclusions and Recommendations

Deepwater offshore exploitations bring a major contribution in meeting the future oil and gas demand. The costs and risks associated with such projects are high and the investments are long-term. Additionally, their viability is affected by the oil price volatility. It is a long way from drilling a successful exploration well to marketing the output, and few companies in the world have the technology, financial strength and management capacity for such projects.

The Black Sea’s potential, even if it is very significant from a theoretical perspective, has not yet been conclusively confirmed. Turkey’s example shows that the uncertainty regarding the potential of resources is not an empty word, Romania, with its discoveries, being an exception.

Investors expect from risky projects, including those in the Black Sea, commensurate returns. If they cannot obtain the returns to match the total risk, the spectrum of offshore projects that are interesting for investors narrows considerably. In such cases, investors may show up that do not have as real objective the project’s profitability, but rather geopolitical interests.

In order to reach the much-discussed win-win situation, from which the society, the state and the investors will benefit, a concurrence of several factors is needed. The materialization of a single major risk can break the project’s chain, because the strength of a chain is given by its weakest link. Therefore, reasonable optimism is useful, but realism as well, with regard to deepwater offshore projects in the Black Sea.

Given the high level of risk in the Black Sea region, Romania needs to act to increase its attractiveness and competitiveness as a destination for capital, technology and know-how in the offshore sector, always taking into account the best practices worldwide, as well as international and regional trends.

The Government of Romania must develop proper institutional and administrative capacity, as well as know-how to manage the particularities of the offshore oil and gas sector. It would have been desirable for the institutional capacity and specialized human resources needed to implement an optimal petroleum fiscal framework to have been already established in the past years.

But even only after the anticipated beginning of the development and production works in the deep waters of the Black Sea, there is a need for the development of a smart and competitive regulatory framework and the creation of institutional capacity to manage the development of a new and rich domain of activity in the energy sector, aligned with the country’s fundamental development goals.