Editor's Note

**Shale gas, a US revolution and a global game changer**

The discovery and successful commercial exploitation of shale gas in the US is both a US revolution and a global game changer.

**A US revolution**

Shale gas has revolutionised the energy landscape of the US by increasing and securing the natural gas supply for the US. This increased and secured natural gas supply has propelled the US on the road from being a net energy importer to becoming a net energy exporter around 2020. Abundance of domestic natural gas has led to a surge in natural gas consumption in the US. This surge has been mainly at the expense of coal, reducing the US' CO₂ emissions by 450 million tonnes in 2012.

**A global game changer**

On a global scale, the increase in US domestic gas supplies, combined with low Henry Hub prices, has created a LNG oversupply and a buyer's market. The US, in an attempt to capitalise on its abundant gas supplies, is in the process of converting some US LNG import terminals into export terminals. Plans are to export gas to China, Europe, Japan and Korea and a 20-year gas supply agreement has already been signed between the US exporter Cheniere Energy Inc. and UK's Centrica Plc, with exports starting in 2018. Another effect of the US shale revolution has been the re-direction of a third of Qatar's gas exports from the US to China. The US shale gas revolution is a real game changer. It is changing global natural gas flows by enabling importing countries to decrease their reliance on some politically unstable regions and thereby altering energy geopolitics.

**Worldwide Shale Oil & Shale Gas Resources**

Since the EIA's 2011 report assessing global shale gas resources outside the US at 5,760 tcf and its revised June 2013 estimate of 6,634 tcf, there has been an increasing focus on the development of...
shale resources outside the US. IOCs, with the majors leading the pack, have ventured outside the US market, in presumed shale gas rich countries, to try to be first on the ground and reap the benefits of the next shale revolution. They have been encouraged in their endeavours by local governments, eager to emulate the US shale revolution and to capture its benefits such as energy security, energy sufficiency, stability of gas prices, boost to the economy and decarbonisation. However, so far, most of these pioneers have encountered disappointing results and some obstacles the US experience did not prepare them for: lack of a suitably skilled oil workforce and an experienced local oilfield services industry, ageing or non-existent transportation infrastructure, inadequacy of current technology to drill economically deeper and muddier shale basins than in the US and shale gas formations located in areas of high population density, amongst other factors.

The US shale revolution was nearly 30 years in the making: 20 years for George Mitchell and his peers to develop adequate technology and 10 years for an economically viable exploitation of shale deposits. Provided that the global demand for gas is forecast to grow, some pioneers will continue to take the long view in continuing their international quest for shale gas.

This Guide aims to help them in their endeavours by both providing a regional overview of shale gas exploration and by taking a focussed look at how certain key contractual issues are addressed by local law in 10 Hot Countries. Each Hot Country has been selected on the basis of reserves, recent regulatory developments, interest we have seen from our client base and IOCs’ activity in that country.

**Hot Countries’ Shale Gas Resources**

The figure shows a bar chart of shale gas resources in various countries, categorized as either “Welcome” or “Cautious and Reserved” approaches to shale gas exploitation.

This Guide includes:

- A general overview of shale gas exploration and production and the key legal issues to consider when negotiating a shale gas permit or licence;
- A quick-reference Aide-Mémoire table comparing conventional vs. unconventional hydrocarbon regimes for the Hot Countries;
• Maps depicting shale gas reserves and policy approaches in Africa/Middle East, Asia Pacific, CIS, Europe, Latin America and North America;

• A structure chart reflecting the administration of oil and gas activities in each of the Hot Countries;

• A map of the key shale gas basins in each of the Hot Countries;

• A table of the companies currently involved in shale gas operations in each of the Hot Countries.

This Guide is intended to be a living document, which we will update regularly to reflect our clients’ needs and evolutions in the industry.

It does not seek to address all the legal or other decisions that an exploration company will need to consider before making an investment in shale. There are, of course multiple other aspects to be analysed. On the legal side alone, companies will need to consider multiple issues: investment structure, vehicle identification, legal and fiscal enforcement regimes, environmental laws, permitting and customs regimes, to name but a few key examples. However, we hope that readers of our Guide will find it a useful source of information on certain key elements that all potential investors in this asset class will inevitably investigate.
A Brief Overview of Shale Gas Exploration and Production

1. Background

1.1 What is shale gas?

Shale gas is natural gas (mostly methane) trapped in sedimentary rocks formed by the solidification of mud deposits in ancient tidal flats and deep water basins. These rocks have been known to contain hydrocarbons for a long time: natural gas seeping from rocks was first reported in 1669 in Ontario County, New York, by the French explorer, Mr de La Salle, and a French missionary, Mr de Galinee. Shallow shale gas formations were also first exploited in New York, with the first commercial natural gas well drilled in Fredonia in 1821 by William Hart, a local gunsmith. By the 1880s, natural gas was widely used in the State of New York for lighting and heat and to supply energy for the drilling of oil wells.

However, with the depletion of shallow shale formations and the Spindletop discovery in 1901 in Texas, the industry focus shifted from natural gas to more easily and economically recoverable crude oil. It has only been since the late 1970s, with domestic supply of crude oil declining in the US and US’ dependency on oil and gas imports increasing that, under the impetus of President Ford, the recovery of unconventional oil and gas (and hence shale gas) re-emerged as an industry focus. By then, two of the key components of the US shale gas revolution were already available: horizontal drilling and hydraulic fracturing. The combination of these two techniques would soon enable oil and gas companies to access gas trapped in deeper, thicker and low permeability formations: shale gas.

1.2 Horizontal drilling

A horizontal well is first drilled vertically and then turned at an angle to horizontally track the target formation along a lateral extent. This exposes more of the wellbore to the target formation, whilst minimizing environmental impact, as only a single surface location is needed for multiple horizontal laterals. Before being used for shale gas exploration and production, horizontal wells were mainly used for plays with a shallow pay zone but extending over a large area (e.g. a formation that is 50 feet thick but thousands of feet in length) or plays where vertical access was difficult or impossible (e.g. a reservoir under a town).

Non-straight line, relatively short-radius drilling, can be traced back to 8 September 1891, when John Smalley Campbell patented the use of flexible shafts to rotate drilling bits in the US (Patent Number 459,152). The prime application for the patent was dental. However, the patent also covered use of flexible shafts at much larger and heavier physical scales such as "... those used in engineers’ shops for drilling holes in boiler-plates or other like heavy work. The flexible shafts or cables ordinarily employed are not capable of being bent to and working at a curve of very short radius ...".

The first true horizontal well, drilled near Texon, Texas, was completed in 1929. However, use of horizontal drilling remained marginal until the 1980s, when improved downhole drilling motors and downhole telemetry equipment made the technology commercially viable.
1.3 Hydraulic Fracturing

Hydraulic Fracturing (commonly referred to as "fracking") is the process of injecting at high pressure water and proppants (known as the "frack fluid") down a wellbore. The pressure of the frack fluid on the target formation causes the target formation to fracture, whilst the proppants in the frack fluid hold open the fractures. This fracturing of the target formation causes the permeability of the formation to be artificially increased and allows the oil and gas to flow more freely back into the wellbore.

Fracking is not a new technology. It dates back to 1947, when Stanolind Oil conducted the first "Hydrafrac" experimental treatment of a well for stimulation in Grant County, Kansas. In 1949, Stanolind Oil patented the use of Hydrafrac and granted an exclusive licence to the Halliburton Oil Well Cementing Company (now Halliburton). That year, Halliburton conducted the first two commercial fracturing treatments in Stephens County, Oklahoma, and Archer County, Texas. At that time, hydraulic fracturing was mainly used to increase a reservoir rock permeability in order to allow the crude oil to flow more easily across the formation to the well. It was only in the 1990s that fracking became more widely associated with shale gas, when George P. Mitchell, an American businessman and founder of Mitchell Energy & Development Corp. (now part of Devon Energy Corporation) successfully applied the technique to the Barnett Shale formation.
2. Exploring and developing a shale play: an overview

2.1 Exploration: Pilot and appraisal phases

Searching for shale gas begins with the acquisition of seismic data over the permit area. This is then followed by an initial exploration phase (generally known as the pilot phase). The pilot phase consists of drilling two to three vertical wells over areas of the permit area which the seismic data identified as being shale formations. The pilot phase will flush out promising areas (also known as sweet spots) for shale gas. These are areas where the shale formations are identified as being of the right maturity and where reserves are technically recoverable. Once the sweet spots have been established, they are used as an anchor for the appraisal phase. The aim of the appraisal phase is to establish whether shale can be produced in commercial quantities. The appraisal phase is characterised by the drilling of fifteen to thirty wells around the sweet spots.

During the appraisal phase, gas will be produced (and typically flared) over a continuous period of time (generally as long as nine months) to establish the long-term economic viability of the shale play. Once an economic play has been ascertained, the project can enter the development phase, which, in a shale gas development, will typically involve the drilling of hundreds of wells.
2.2 Exploitation: Development phase

In a shale gas development, the geology of shale leads to a markedly different production profile than that of conventional oil. Conventional oil production profiles are typically characterised by a quick steep increase, followed by a long plateau, then a steep decline leading quickly to the end of the economic life of the field. Shale gas production profiles display a slower steep incline, followed by a short plateau (due to the limited drainage pattern of shale gas), then a steep decline followed by a long up and down tail reflecting the depletion of individual well bores and new well bores being brought online. This tail is expected to last for years.

These different production profiles are accentuated by the divergent approaches taken in developing oil fields and natural gas fields. As the oil market is very liquid, oil production can be disposed of quickly and easily. This quick and easy disposal of oil leads to an accelerated production of oil fields characterised by a quick depletion of reserves. On the other hand, long term sales contracts, which are a pre-requisite to most natural gas field developments, dictate a slower depletion of reserves because the development of natural gas fields is carried out with a view to matching the long term commitments of the underlying long-term gas sales contract (i.e. provision of a specified quantity of gas for periods ranging from 10 to 20 years), resulting in a much longer declining tail than for oil fields.

To be economically viable, given the limited drainage pattern of shale wells, shale programs require the continuous drilling of new commercially producing wells. These new commercially producing wells will be anchored to the main infrastructure throughout the exploitation period. In order to identify such wells, exploration and appraisal wells will need to be drilled continuously throughout the exploitation phase. This requirement of continuous exploration and appraisal will in turn impact companies’ requirements as to the terms of permits in order to ensure commerciality and economic viability of projects.
Negotiating an Unconventional Hydrocarbons Permit: Key Contractual Issues to Consider

1. Introduction

Due to the geology of shale plays, seismic surveys are of limited utility: they provide an indication as to the existence and location of a play but no information as to its quality (thermal maturity, depth of burial, potential flow rate, commerciality), nor its extent. As explained above, the geology of a shale play can vary substantially throughout the play, requiring constant exploration and drilling (and hence investments) to first identify sweet spots and then, once commerciality of a play has been established, to maintain commercial flow rates throughout production. Effectively, this means that exploration and exploitation permits construed and awarded for conventional hydrocarbons exploration and exploitation will often be unsuitable for the exploration and production of unconventional hydrocarbons. This chapter aims to highlight the key terms of permits, petroleum agreements, production sharing agreements or licences that may need to be negotiated to allow for an economically viable shale gas development. The following chapters of this Guide will then analyse/present how these key terms are addressed in the 10 countries we have identified as "hot spots" for shale gas exploration and production. These are: Algeria, Argentina, Australia, China, Poland, Russia, South Africa, UK, Ukraine and the US ("Hot Countries").

2. Key contractual issues for a shale gas project

2.1 Longer initial exploration term and exploration during production required

Most companies searching for shale gas in the international (non-US) arena start their work under a reconnaissance licence or an exploration permit. The authority granted by reconnaissance licences is generally limited to the acquisition of seismic data and, unlike exploration permits, does not typically allow for exploratory drilling. As seismic data is of limited utility for shale gas exploration, this Guide will not consider reconnaissance licences in further detail.

As explained above, during the exploration phase of a shale gas program a multitude of exploration and appraisal wells will need to be drilled before establishing the commerciality of a play. For example, in an area of 200 km², establishing commerciality could entail drilling three exploration wells and approximately 10 appraisal wells. Given the number of wells required to be drilled in shale gas operations, longer than usual exploration periods are necessary.

Most host countries' exploration permits will be of limited duration and grant the right to apply for an exploitation permit once hydrocarbons have been discovered in commercial quantity. In a shale play, exploration will not stop once production has started but will need to continue throughout production in order to maintain a commercially viable production. This means that when applying for a permit to explore and exploit unconventional hydrocarbons, companies should ensure that they are granted the right to continue exploration during the exploitation period.

2.2 No relinquishments

Relinquishments are widely used throughout hydrocarbon-producing countries as a way to incentivise the permit holders to assess the potential of its permit as soon as possible rather than
delaying. The rationale for relinquishments is that mandatory loss of a section of the permit area after a certain period of time motivates the permit holder to acquire seismic data timely to find the propitious areas within its permit. The permit holder can then relinquish the areas with little or less prospectivity than the most promising areas. Such an approach works for conventional hydrocarbons exploration as seismic data makes it possible for geologists and geophysicists to ascertain with sufficient accuracy the geological formations containing conventional hydrocarbons and to extrapolate the extent of the same. However, such an approach does not make sense for unconventional hydrocarbons given that seismic surveys provide little indication as to whether the relevant geological formations will, when hydraulically fractured, produce hydrocarbons in commercially viable quantities. As explained above, evaluating an unconventional shale gas play will require the drilling of a number of exploration and appraisal wells over large geographic areas within a permit area and flow testing the wells (by flaring gas) for an extended period. Likewise, the development of a shale gas play will entail continuous drilling of exploration and appraisal wells.

Given the heterogeneity of shale plays and the large number of wells required to assess the commerciality of an area of a permit, by the time a relinquishment obligation arises a permit holder is unlikely to have assessed the potential of the entire permit area in order to make an informed decision as to which part of the permit area to relinquish.

Should acreage be relinquished in the context of a shale gas development, the relinquished lands are likely either to be stranded within an area kept by the permit holder or to be in the most isolated and inaccessible section of the original permit area. Therefore, third parties are likely to consider such relinquished lands not attractive enough to form the basis of a new stand-alone permit. In addition, due to the continuous and extensive nature of shale gas operations, areas that may have been considered too remote or not promising enough when first deciding upon the commerciality of the play may, as pipeline and processing infrastructure expand over wider geographic areas, be considered economical to develop as they can be easily connected to then existing infrastructure. Developing such remote or less promising areas may not be possible for a new permit holder as it may not benefit from the existing infrastructure developed by the original permit holder. Hence, having compulsory relinquishment of areas in a shale gas development may actually be counterproductive and prevent the optimal development of the relinquished areas.

Given the need for companies to continuously drill exploratory and appraisal wells to ensure a commercially viable shale gas development and the risk of relinquished areas not being developed by new permit holders (due to lack of synergies), companies may argue that relinquishments are not needed in the context of shale gas development and that the economics of shale gas development are incentive enough for exploration.

2.3 Exploitation term

Shale gas developments, due to the requirement for continuous exploratory and appraisal drilling throughout the exploitation term, have a sustained capital investment profile (i.e. constant capital investment is needed) and a slower break-even point. In contrast, conventional development typically has a shorter capital investment profile (large initial cash sink) and a faster break-even point, after which production continues for years without very significant further capital investment. This sustained capital investment profile, combined with the limited drainage pattern and followed by a long declining "tail", means that to be sufficiently economically viable for development shale plays typically require longer production periods than conventional plays: 40-
50 years based on current US play estimates (instead of the 25-30 years usually awarded for conventional hydrocarbons). In addition, as discussed above, the need for longer exploitation periods for shale plays is also accounted for by the long term gas sales contracts underlying most natural gas field developments.

2.4 Delineation exploitation concession

Unlike conventional hydrocarbon reservoirs, shale gas formations are pervasive in nature and not restricted to clearly defined areas. In addition, US experience has demonstrated that shale plays are very heterogeneous: the geophysical and geological characteristics of a shale play (rock properties, thermal maturity and depth of burial) can vary greatly over very short distances of 500m or less. In practice, this means that well productivity can vary considerably over very short distances. For example, a well located 3 km away from a well producing in commercial quantities could be non-producing.

Companies in the shale gas exploration and production business aim to identify:

- primary sweet spots, being areas of a shale formation that have relatively high productivity wells, from which to anchor a shale gas development; and
- secondary sweet spots, being areas which do not necessarily have the highest producing wells but which, if certain factors vary (such as technology, infrastructure, price of gas), can become economical to develop and contain value sweet spots, being areas of a shale play that generate the highest revenue. The idea is to declare a concession area over an acreage large enough to cover both the primary sweet spots and the secondary sweet spots.

If the approach used for conventional oil and gas was used to delineate a shale exploitation concession, it would mean that, to be able to clearly characterise the perimeter of the shale concession, a company would need to drill a considerable number of exploration and appraisal wells during the exploration permit without being able to sell production from already producing wells. From a company's perspective, such an approach would be uneconomical and risky. This is why, in the context of shale gas exploration and production, companies look for legal regimes that are flexible enough to allow for the declaration of an exploitation concession:

- wide enough to encompass a reasonably large perimeter (e.g. 15 km radius circle) surrounding the exploration and appraisal wells that are the anchor of the program and the basis for the exploitation concession application; or
- by reference to the deposit, being the relevant geological formations for unconventional hydrocarbons (i.e. the target intervals) within which the presence of hydrocarbons has been proven by an exploration and/or appraisal well penetrating such geological formations.
2.5 National Oil and Gas Company participation and carry

In many non-western countries, the national oil and gas legislation provides for:

• compulsory state participation in hydrocarbon exploration and production; and

• often, for exploration costs to be borne by the international oil and gas company ("IOC") alone or advanced by the IOC and reimbursed by the state during exploitation.

As explained above, shale operations require many more wells at each of the exploration, appraisal and production phases than is the case with conventional operations. Drilling and completing a shale gas well is also much more expensive than drilling a conventional gas well,
and such costs can vary depending on the geology of the play. For example, in the US, drilling and completing a conventional vertical onshore well might cost between US$ 1 and 3 million, while an unconventional well can cost up to US$ 5 to 8 million. In contrast, assuming the same depth and number of laterals, drilling and completion of such an unconventional well in Poland or China might well cost in the US$ 14 to 16 million range.

To put things into perspective, various reports have estimated exploration and production costs for unconventional hydrocarbons to be approximately between 15 to 25 times higher than for conventional hydrocarbons.

Higher exploration and production costs for shale gas projects, coupled with a higher number of wells and generally low cash flows/capex of national oil companies ("NOCs") mean that, from an IOC's perspective:

- it is preferable to agree to a lower state participation than for conventional projects;
- having a government carry through exploration may adversely affect the economic viability of the project; and
- a clear right to sole risk with a limited back-in right for NOCs (ideally none) will be the preferred option.

Possible solutions to resolve the tensions between NOCs and IOCs around the negotiation of state participation and state carry may involve one or more of the following:

- a reduction of the state's participation percentage interest for unconventional petroleum agreements to a lower level;
- enshrining in the petroleum agreement (or equivalent instrument) a compulsory reimbursement by the state to the permit holder of the carried costs of exploration and appraisal within a certain period from the commencement of commercial production;
- limiting the number of exploration and/or appraisal wells for which the state is carried;
- limiting the time period for which exploration costs carry will apply; and/or
- capping the amount of costs for which the IOC would carry the state.

Finally, any discussion around state participation and carry will need to encompass a careful analysis of the definitions of exploration wells (and associated works program), appraisal wells (and associated works program) and consequences of these definitions. The reason for this requirement flows from the above but, by way of example, in a petroleum agreement for conventional hydrocarbons, the state carry will cease with the discovery of hydrocarbons and the onset of the exploitation term. However, due to continued exploration during exploitation and the need to drill appraisal wells once hydrocarbons have been discovered, there is no clear demarcation between exploration and exploitation in shale gas projects.

### 2.6 Water resources rights

Large volumes of water are required throughout the life of a shale gas project (from the drilling and fracking of wells to the cleaning of the equipment). However, as fracking is the most water intensive stage and the one that has been subject to much commentary and scrutiny, this Guide will concentrate on the amount of water used for fracking wells.
The amount of water required to frack a well will vary from well to well. Factors influencing the total volume of water used to frack a well include the depth, length and number of horizontal segments fracked as well as the geological characteristics of the shale play (depth, thickness, total porosity, maturity). For example, in the US, an average of five million gallons of water is used per well (approximately 18,927 m$^3$), with the Haynesville and the Marcellus Shale being the most water intensive (an average of 5.6 million gallons per well) and the Bakken shale being the least water intensive (two million gallons per well). Such numbers appear very large, but they are relatively low when compared with water consumption by other sectors (agricultural, industrial) or with a state’s total water consumption.

### Water Usage in Perspective

<table>
<thead>
<tr>
<th>Shale Play</th>
<th>Depth in feet</th>
<th>Per well</th>
<th>Per play</th>
<th>Daily</th>
<th>Annually</th>
<th>Per well</th>
<th>Per play</th>
</tr>
</thead>
<tbody>
<tr>
<td>Eagle Ford (Texas)</td>
<td>4,000 to 14,000</td>
<td>6</td>
<td>1,368</td>
<td>26700</td>
<td>9745500</td>
<td>0.00060%</td>
<td>0.01404%</td>
</tr>
<tr>
<td>Permian (Texas)</td>
<td>8,525</td>
<td>4</td>
<td>1,872</td>
<td>26700</td>
<td>9745500</td>
<td>0.00004%</td>
<td>0.01921%</td>
</tr>
<tr>
<td>Bakken (North Dakota)</td>
<td>10,560</td>
<td>2</td>
<td>360</td>
<td>1,340</td>
<td>489100</td>
<td>0.00041%</td>
<td>0.07360%</td>
</tr>
<tr>
<td>Marcellus (Pennsylvania)</td>
<td>4,000 to 8,500</td>
<td>5</td>
<td>425</td>
<td>9,470</td>
<td>3,456,500</td>
<td>0.00014%</td>
<td>0.01230%</td>
</tr>
<tr>
<td>Haynesville (Arkansas, Louisiana, and Texas)</td>
<td>10,500 to 13,000</td>
<td>5.6</td>
<td>151.2</td>
<td>32,470</td>
<td>1,185,150</td>
<td>0.00005%</td>
<td>0.00128%</td>
</tr>
<tr>
<td>Barnett (Texas)</td>
<td>6,500 to 8,500</td>
<td>2.5</td>
<td>85</td>
<td>2,670</td>
<td>974,550</td>
<td>0.00003%</td>
<td>0.00087%</td>
</tr>
<tr>
<td>Niobrara (Colorado)</td>
<td>6,000 to 10,000</td>
<td>4.3</td>
<td>215</td>
<td>13,600</td>
<td>496,400</td>
<td>0.00009%</td>
<td>0.00433%</td>
</tr>
<tr>
<td>Fayetteville (Arkansas)</td>
<td>10,000</td>
<td>4.9</td>
<td>44.1</td>
<td>11,400</td>
<td>416,100</td>
<td>0.00012%</td>
<td>0.00106%</td>
</tr>
<tr>
<td>Utica (New York, Pennsylvania, Ohio, West Virginia, Louisiana and Mississippi)</td>
<td>3,000 to 7,000</td>
<td>4.8</td>
<td>182.4</td>
<td>40,980</td>
<td>1,495,770</td>
<td>0.00003%</td>
<td>0.00122%</td>
</tr>
<tr>
<td>Tuscaloosa Marine (Louisiana and Mississippi)</td>
<td>11,000 to 15,000</td>
<td>4.8</td>
<td>14.4</td>
<td>14,530</td>
<td>53,034,50</td>
<td>0.00009%</td>
<td>0.00027%</td>
</tr>
</tbody>
</table>

Given the sizeable water requirements of shale gas operations, a key challenge for companies engaged in shale gas exploration and production is to secure a sufficient volume of water (preferably fresh water, as brackish water is more likely to damage the equipment, require a higher concentration of proppants and result in formation damage) for fracking and drilling. In particular, exploration companies will want to secure water rights at reasonable agreed costs stabilised for the entire project life, as such costs will constitute an integral factor in determining whether or not a project is economically viable. It is therefore important to look carefully at whether a country's regime provides water rights for the duration of a project (right to withdraw water from lakes and rivers, right to drill source wells to access groundwater, right to use such water and right to install any necessary water infrastructure facilities) as well as a level of stability or predictability as to what the water costs will be (e.g. fixed royalty rates for water usage).
2.7 Flaring

Flaring can be defined as the controlled burning of natural gas. It was used in oil and gas operations long before it was brought to the public's attention in the context of shale gas exploration and production. For example, in conventional oil and gas operations, flaring is used:

• as a safety device, particularly at gas processing plants: when equipment or piping becomes over-pressured, special valves automatically release gas through piping to flare stacks, diminishing the risk of fires and explosions;

• as an outlet for gas during maintenance and equipment repairs; and

• to manage volumes of waste gas that cannot be captured and processed.

In shale gas operations, flaring is used to test the pressure, flow and composition of the gas or oil from the well. What characterises flaring in the unconventional hydrocarbon operations context is the length of time gas is flared: often anywhere from six to nine months. Such a long flaring period is required because, commercially, a demonstration of a continuous production period is needed to assess the economic viability of a well. Using the flow rates during this production period, projections are made as to future flow rates and ultimate recoverable reserve estimates for the area surrounding the relevant wells (generally 10 to 20 appraisal wells will need to be flared simultaneously to evaluate the prospectivity of a given area).

Given the importance of flaring to establish the economic viability of a shale gas project, companies will need to secure flaring permits, from the outset of a shale gas project, enabling flaring in the volumes and for the duration required to assess whether a project is commercially viable.

2.8 Stability

Stability clauses aim to enshrine for the life of a project the respective rights and obligations of the parties as they are negotiated on the effective date of the contract. In the oil and gas exploration and production context, stability clauses seek to prevent the unilateral and adverse revision by a host government (e.g. through the passage of new legislation) of the terms and conditions of the petroleum agreement. If such unilateral revision arises (and a stability clause has been included), the host government will generally be required to compensate the IOC. Two key types of stability provisions can be distinguished: fiscal stabilisation, which only applies to the fiscal elements of the petroleum agreement, and full contractual stabilisation, which extends to all elements of the petroleum agreement.

Given the capital intensive nature of shale gas operations and the long payback period (40 to 50 years exploitation term, with a continuous drilling program), IOCs will seek full stabilisation of the petroleum agreement to protect their investment from adverse changes in laws and/or regulations or the adoption of adverse new laws and/or regulations. In particular IOCs will want to ensure that the following are fixed at the outset and for the life of the project:

• any taxes, duties and fees in connection with the transfer and/or assignment of interests in the exploration permit and/or the exploitation concession;

• royalties, surface rentals, etc.;

• rights and obligations of the permit holder arising from the laws and regulations governing hydrocarbon operations (in particular any law/regulation governing environmental liability);
• any taxes and/or fees payable for flaring and/or water usage; and
• a mechanism to deal with compensation of the permit holder if any of the stabilised terms and conditions are adversely changed by new laws/regulations or changes in laws/regulations (e.g. economic rebalancing provision including a stipulated result to be achieved by such provision).

3. Other contractual issues to consider

This section contains some other contractual issues which are usually considered by exploration companies in oil and gas projects and that will also be relevant to shale gas projects.

3.1 Domestic market obligations

Domestic market obligations ("DMO") represent an obligation for the IOC to sell a portion of its hydrocarbon production to the domestic market (i.e. the country in which the hydrocarbon operations take place). DMO are quite common in petroleum agreements. If an IOC is subject to DMO, it may want to consider the following issues:

• the extent of DMO obligation, in particular in comparison with the DMO of other IOCs operating in the country. Is it a pro-rata DMO relative to the total hydrocarbon production in the domestic market?
• does the IOC have the right to export hydrocarbons once it has fulfilled its DMO?
• how is the sale price in the domestic market determined? Is it a fair market pricing or does the domestic sale price calculation result in a lower price than the international market price (e.g. production cost)?
• what is the currency in which the hydrocarbons sold pursuant to the DMO are paid? Is payment in local currency compulsory?
• does the IOC have the right to repatriate proceeds and profits from hydrocarbon sales (both domestic and exports) into the IOC’s preferred jurisdiction?
• what is the definition of “domestic market”. In particular, is gas used as feedstock for exports included in the definition?
• is there an existing market to purchase the hydrocarbons to be sold pursuant to the DMO? If not, will the host country purchase such hydrocarbons as an aggregator?
• does the IOC have the right to suspend delivery of hydrocarbons to be sold pursuant to DMO without breach if there is a payment default by the domestic buyer?

In the context of shale gas, a fair market pricing mechanism is crucial as shale gas projects are capital intensive and require fairly high natural gas prices to be economically viable. In order to be comfortable with investing in a country, IOCs will need certainty as to the determination of natural gas prices, preferably through linking natural gas pricing to crude oil prices (variables that IOCs are very familiar with and well able to budget around), unless there is a reliable gas market pricing mechanism.

3.2 Fiscal regime and tax incentives

IOCs will also need to consider the host government's fiscal regime and in particular any tax incentives provided for shale gas operations.
3.3 Third party and state access to infrastructure

If a shale gas project is located in a remote area with little or no access to infrastructure and the IOC will have to build transportation and gathering infrastructure to develop its shale gas project, the IOC may want to consider:

- to what extent will third parties have the right to access such infrastructure? Ideally, third parties will only have the right to access when there is excess capacity and subject to the payment of compensation covering the IOC’s overheads for operating the infrastructure and also enabling the IOC to make a profit; and

- the state’s right of access to such infrastructure. To the extent legally permissible, these should be the same as other third party users.
Africa and Middle East

1. Introduction

In Africa and the Middle East, there are only a handful of countries with shale potential: Algeria, Egypt, Libya, Morocco, South Africa, Tunisia and Turkey for Africa, and Jordan and Saudi Arabia for the Middle East.

As displayed on the map below, in Africa and the Middle East, countries have either decided to welcome shale gas exploration or to take a cautious and reserved approach. Whilst there was a temporary moratorium on shale gas exploration in South Africa, there is currently no outright opposition to, or ban on, the exploration for shale gas in the Africa and Middle East regions.

![Africa and Middle East: Shale Gas Reserves and Policy Approaches](image)

2. Africa

2.1 A bright future for shale gas in Africa?

Africa has been deemed the "new frontier for economic growth". In its 2011 report entitled Africa in 50 Years’ Time, The Road Towards Inclusive Growth, the African Development Bank projects that by 2030 much of Africa will attain lower-middle and middle-class majorities. Further, Africa will likely represent US$ 2.2 trillion in annual consumer spending (from US$ 680 billion in 2008) and about 3% of worldwide consumption.
Echoing these projections, many companies representing various industries have rushed to Africa in the last five years, and private equity is slowly beginning to invest in the region.

Africa’s key advantages for shale gas development are:

- its strategic position, being close to both Europe and Asia, which are two of the biggest consumers of natural gas;
- generally attractive licensing terms compared with Middle Eastern and Western countries;
- cheap labour;
- a growing middle class leading to a growing local demand for energy; and
- support from the African Development Bank (in a report entitled *Shale Gas and its Implications for Africa and the African Development Bank*, the African Development Bank stated its willingness to "support those of its member countries that have shale gas prospects".

### 2.2 Key challenges for a shale gas revolution in Africa

#### 2.2.1 Novelty of unconventional resources

Africa, whilst free of its colonial masters, still tends to look north to Europe for guidance when confronted by new issues and concepts. In the context of shale gas, this has been the attitude of some countries, like South Africa, which enacted a temporary moratorium on hydraulic fracturing operations (which has since been lifted), and Tunisia, which is taking a cautious and reserved approach to shale gas development. Both of these approaches reflect in part the attitudes of the UK and France. There is however a clear need and an eagerness in Africa to be "educated" on the specificities of shale gas developments and IOCs have seized these opportunities by organising a number of conferences in North Africa on shale gas.

#### 2.2.2 Logistical constraints

At the moment, there is a lack of:

- a skilled workforce and an experienced oilfield services industry;
- access to drilling rigs capable of drilling horizontally; and
- gathering, transporting, processing and refining infrastructure. This infrastructure shortage is emphasised by the fact that African shale plays tend to be in remote locations where there is little or no water, roads or power. Remediying such shortage will require considerable capital investments.

In addition, any shale gas project in Africa will have to factor in political instability (especially in the wake of the Arab Spring) and often inefficient administration (slow processes to obtain approvals), which is likely to lead to considerable delays and costs.

#### 2.2.3 Legal constraints

Most of the oil and gas regimes in Africa provide for:

- exploration and exploitation periods which are too short for a shale gas project;
- NOC participation and carry;
- relinquishments obligations;
• DMO;
• foreign exchange controls;
• a delineation of exploitation concessions by reference to the structural feature identified by seismic and exploration drilling; and
• no provisions for flaring.

To have a successful US-style shale gas revolution, Africa will need to tackle these logistical and legal constraints. Given that the pace of change can be slow throughout Africa, African countries will no doubt already be considering necessary reforms to ensure that adequate infrastructure and, perhaps more importantly, adequate legal regimes are in place by the time IOCs have to make final investment decisions on their African shale projects.

3. Middle East

3.1 Only two countries with shale potential

Studies have proved that, in the Middle East, both Jordan and Saudi Arabia have technically recoverable shale gas resources, 7 trillion cubic feet ("tcf") and 645 tcf respectively. However, it is likely that, due to its more important shale gas resources and its established oil and gas infrastructure, Saudi Arabia will be IOCs' preferred choice for shale gas developments.

In October 2013, Saudi Aramco announced that it would be ready to start producing its shale gas resources in the next few years. Saudi Aramco plans to use domestically produced shale gas to cater to the needs of its growing national energy consumption (with demand expected to double by 2030), thus freeing more oil for exports. In particular, there are plans to use shale gas as feedstock to feed a proposed power plant in Jizan, which will be connected to a 400,000 barrels-per-day ("bpd") refinery.

To date, Saudi Aramco has carried out exploratory and appraisal drilling in three prospective areas: the northwest, the south Ghawar and the Rub' al-Khali.

3.2 Ambivalence towards shale gas

According to the International Energy Agency ("IEA"), the US is on track to become the number one oil producer in the world by 2017 and a net exporter by 2030. Some analysts are even more optimistic and predict that the US will be a net energy exporter around 2020.

Analysts have predicted that the rise of unconventional hydrocarbon production in the US constitutes a threat to the Gulf region's oil exports and petrochemical industry. These predictions have been given weight with the shelving by Saudi Arabia of its planned crude output capacity extension from 12 million bpd to 15 million bpd and the re-direction of a third of Qatar's gas exports from the US to China.

However, things must be kept in perspective. The US is only beginning the process of converting its liquefied natural gas ("LNG") import terminals into LNG export terminals, with plans to cap the number of LNG export terminals to non-Free Trade Area countries and to impose export quotas. Such caps and quotas aim to retain sufficient natural gas to fuel the re-birth of petrochemical and manufacturing industries in the US (i.e. lower fuel costs enable companies to price products more cheaply and hence to be more competitive on the international markets). At the time of writing, only four export terminals to non-Free Trade Area countries had been approved...
(Cheniere's Sabine Pass (2.2 bcf/d), Freeport (1.4 bcf/d, with a conditionally authorised increase of 0.4 bcf/d), Lake Charles Exports (2.0 bcf/d) and Dominion (0.77 bcf/d)).

The time needed to convert an LNG import terminal into an LNG export terminal (approximately three to four years), the planned caps on the number of such terminals, and quotas on the amount of gas available for export and the time needed to re-direct oil production to Asian markets effectively mean that rising production in the US does not constitute an immediate threat to the Gulf's oil exports and petrochemical industry.

In the medium term, provided economic growth keeps its pace in the Asian markets, Asia's hunger for energy is set to continue increasing, providing a stable customer base for Middle East oil exports. This, coupled with a rising domestic energy consumption (growing 8% to 10% annually) in the Gulf and the natural gas/oil price sensitivity of shale gas projects (i.e. shale gas projects are not economically feasible if natural gas/oil prices decline below a certain point) means that the Gulf oil and gas industries can still feel confident about the future. However, this does not mean that Gulf countries should ignore some of their latent problems such as subsidised domestic oil and gas prices and heavy reliance on the oil and gas industry as the driver of economic growth. Gulf countries would be wise to take a long term view and continue on their path of industry diversification and consider cutting domestic subsidies for oil and gas.

4. **Up-and-coming shale countries**

**Middle East and Africa - Shale Gas Resources**

![Shale Gas Resources Graph](chart.png)

*Note: This graph is based on unproved shale gas technically recoverable resources as per the EIA Report.*
On the basis of the map and graph above, recent regulatory developments as well as interest we have seen from our client base, we have identified Algeria and South Africa as being the countries with perhaps the most immediate prospects for shale gas development in Africa. The next two chapters explore how these countries’ legislation addresses some of the key contractual issues to consider for a shale gas project.
Algeria

1. **Introduction**

1.1 **Industry background**

Algeria is now the third largest natural gas producer in the Arab world, after Qatar and Saudi Arabia, and the leading gas exporter in Africa (exporting to China, France, Italy, Spain, Turkey and the US). According to the EIA’s estimates, in terms of conventional hydrocarbons, Algeria has 12.2 billion barrels of proven crude oil reserves, 160 tcf in reserves of natural gas, and 707 tcf of technically recoverable shale gas reserves. Algeria has been a member of the Organisation of the Petroleum Exporting Countries since 1969 (shortly after it began oil production in 1958).

Sonatrach SpA ("Sonatrach"), the country’s NOC, owns 80% of hydrocarbon production in Algeria under a legal majority stake requirement, with the remaining 20% owned by IOCs. In recent years oil production has slowed, falling to its lowest level since 2003 in July 2013. This has been attributed to a number of factors, including; security concerns (with militant groups attacking gas facilities, e.g. at the In Amenas facility in January 2013), concern over possible corruption (note the probes into Sonatrach and the Energy Ministry in 2010) and delays in the granting of licences.

1.2 **Legal framework**

Algeria is unique in Africa; it is the only country to date to have amended its legislation to provide for unconventional hydrocarbons developments. Indeed, Law no. 13-01 of 20 February 2013 amending and supplementing Law no. 05-07 of 28 April 2005 relating to hydrocarbons ("HL") specifically covers the exploration and production of unconventional hydrocarbons. However, please note that this chapter only examines the regime applicable to unconventional hydrocarbons exploration and production. For a brief overview of the regime applicable to conventional hydrocarbons, please refer to the Shale Gas Aide-Mémoire at the end of this Guide.

1.3 **Ownership of hydrocarbon resources**

Pursuant to Article 3 HL, the Algerian state is the owner of all hydrocarbon resources. However, the Algerian state has no direct participation in hydrocarbon exploration and production activities. Instead, ALNAFT (as defined below), an independent agency enters into contracts with IOCs for the exploration and production of hydrocarbons on the Algerian state’s behalf.
1.4 Administration

Administration of Oil & Gas Activities in Algeria

As shown in the schematic above, in Algeria the key regulators and players in the oil and gas sector are:

- **Ministère de l’Énergie et des Mines** (in English, the Ministry of Energy and Mines, "MEM"). MEM’s role consists of:
  - preparing and implementing laws, regulations and policies for the energy and mining sector;
  - reviewing and approving petroleum agreements and operating agreements; and
  - issuing pipeline concessions (Articles 68-69 HL).

- **Agence Nationale pour la Valorisation des Resources en Hydrocarbures** (in English, National Agency for the Development of Hydrocarbon Resources, "ALNAFT"). ALNAFT is an independent agency, and pursuant to Article 14 HL its responsibilities include:
  - managing and updating databases on the exploration and exploitation of hydrocarbons;
  - granting prospecting authorisations;
  - issuing competitive calls for bids and assessing bids for exploration and/or exploitation activities;
  - holding the mining title (the basis for the grant of exploration and exploitation contracts) and entering into exploration and/or exploitation contracts, subject to MEM’s approval;
  - monitoring and controlling, in its capacity as contracting party, the implementation of exploration and/or exploitation contracts pursuant to the HL;
  - studying and approving development plans and their periodic updates;
  - collaborating with MEM for the implementation of policies and the preparation of regulations governing hydrocarbon activities;
  - following-up, controlling and auditing exploration and/or exploitation costs; and
•  determining and collecting royalties and paying the same to the Treasury.

•  **Agence Nationale de Contrôle et de Régulation des Activités dans le domaine des Hydrocarbures** (in English, National Agency for the Control and Regulation of Activities in the hydrocarbon sector “ARH”). ARH is also an independent agency, and pursuant to Article 13 HL its responsibilities include:
  
  o  ensuring the observation of the regulations applicable to the oil and gas industry (e.g. technical regulations, health, industrial safety and environmental regulations, etc.);
  o  reviewing applications for licences for transportation by pipeline and making recommendations for the award of the same to MEM;
  o  reviewing applications for the exercise of refining and storage activities and the distribution of petroleum products and recommending the award of an authorisation to carry out these activities to the Minister for Hydrocarbons;
  o  monitoring the running of the hydrocarbons and petroleum products transportation tariffs adjustment and compensation system, under conditions defined by regulation;
  o  collaborating with MEM for the implementation of policies and the preparation of regulations governing hydrocarbon activities; and
  o  organising an internal conciliation service for disputes resulting from the application of hydrocarbons regulations, particularly those relating to pipeline transportation access, petroleum products storage systems and tariffs.

•  **Sonatrach.** Sonatrach is the NOC. Sonatrach is wholly owned by the Algerian state and is in charge of the exploration, exploitation, transportation, processing and marketing of hydrocarbons.

2. **Key contractual issues for a shale gas project**

2.1  **Exploration term**

Pursuant to Article 35 HL, the exploration term can last up to a maximum of 11 years, divided into an initial phase of three years, a second and third exploration phase each having a duration of two years and a pilot phase of four years (granted by ALNAFT).

Further to Article 46 HL, during the pilot phase the contractor can request an authorisation for early production. However, the purpose of the pilot phase is not clearly stated by the HL (i.e. appraisal, early production or continued exploration?), nor does it identify the criteria that must be met to be granted such a pilot phase (i.e. is a discovery needed?).

In addition, Article 37 HL provides that the contractor can ask for the following extensions:

•  an exceptional six month extension of the exploration term to complete drilling works that began prior to expiry of exploration period; and

•  if a discovery is made before the expiry of the exploration term, a maximum two year extension to enable it to complete appraisal work on such discovery. Such extension will be reduced by any extension to complete drilling works already granted and must be approved by ALNAFT together with the appraisal work program for such extension.

The extensions set out in Article 37 seem to apply to unconventional hydrocarbons. However, it is unclear how they interact with the four year pilot phase.
Finally, Article 42 HL provides that if, due to limited infrastructure or absence of a market for gas, the contractor has made a discovery but cannot make a declaration of commerciality, it can notify ALNAFT, prior to expiry of the exploration term, of its decision to retain the area for three years for oil and wet gas fields or for five years for dry gas fields.

Regarding the size of the permit area, Article 19 HL provides that the hydrocarbon sector is to be divided into four zones: A, B, C and D, and that the maximum size of each zone will be defined by regulation. To date, Degree No. 07-127 of 5 May 2009, as amended by Decree No. 10-21 of 12 January 2010 ("Perimeter Decree") regulates the size of prospecting, exploration and exploitation perimeters.

Pursuant to Article 7 of the Perimeter Decree, the maximum perimeters for prospecting, exploration and exploitation permits are as follows:

<table>
<thead>
<tr>
<th>Zone</th>
<th>Maximum Perimeters (in blocks)</th>
<th>Maximum Perimeter in km²</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>100</td>
<td>6,400</td>
</tr>
<tr>
<td>B</td>
<td>75</td>
<td>4,800</td>
</tr>
<tr>
<td>C</td>
<td>55</td>
<td>3,520</td>
</tr>
<tr>
<td>D</td>
<td>25</td>
<td>1,600</td>
</tr>
<tr>
<td>Offshore</td>
<td>150</td>
<td>9,600</td>
</tr>
</tbody>
</table>

Under Algerian law, a block is defined as a square of 8 km on each side.

2.2 Relinquishments

Article 38 HL provides that the specific terms and conditions of relinquishments must be set out in the concession contract, provided that at the end of the exploration period "all areas and geological horizons not covered by the development plan approved by […] ALNAFT are relinquished". Article 38 HL further provides that if the areas and/or geological horizon relinquished are put out to competitive bid, a preference may be granted to the contractor having relinquished such areas provided that the contractor equals the best bid selected.

2.3 Exploitation term

Pursuant to Article 35 HL, the exploitation term is:

- 30 years for the exploitation of unconventional liquid hydrocarbons; and
- 40 years for the exploitation of unconventional gaseous hydrocarbons.

Article 35 HL provides that a contractor may ask for two further extensions of five years each, with the second extension requiring ALNAFT's approval (i.e. the possibility of a total additional extension of 10 years). It further provides that if an exploration phase has not been used, the exploitation term will be increased by a period equal to said phase.

Finally Article 24 HL seems to imply a right for the contractor to continue exploration during the exploitation period by stipulating that, if the contractor makes a chance discovery during the exploitation term in the geological formation set out in the relevant development plan, the
contractor can claim a right to such chance discovery. Article 25 further defines a chance discovery as "any hydrocarbon accumulation not included in the development plan approved by ALNAFT".

2.4 Delineation exploitation concession

Article 47 HL states that for unconventional hydrocarbons, the outline terms and conditions of the development plan will be specified in the concession contract. This Article seems to leave the door open for the contractor to negotiate with ALNAFT the perimeter of its exploitation concession.

2.5 NOC participation and carry

Pursuant to Article 32 HL, Sonatrach must hold a minimum 51% interest in all exploration and exploitation contracts.

Regarding exploration costs, the general principle is that these are borne by the contractor (Article 48 HL). However, Article 48 HL further provides that Sonatrach has the option to participate in exploration costs. This optionality has probably been included by the legislators to address the much higher costs of exploration for unconventional hydrocarbons compared to conventional hydrocarbons exploration costs, and is unlikely to be used by Sonatrach for conventional projects.

If Sonatrach decides to participate in exploration costs, the contractor will have to advance Sonatrach's share of the exploration costs and Sonatrach will reimburse the same pursuant to the terms and conditions agreed by the contractor and Sonatrach in the exploration and exploitation contract.

2.6 Water resources rights

Article 53 HL provides that if water is taken from the public water domain and used for petroleum operations, the contractor must:

- for unconventional hydrocarbons operations, obtain a licence or authorisation, issued by the relevant authority in coordination with ALNAFT, for the taking and use of such water; and
- pay a non-deductible tax for the use of such water in accordance with the laws and regulations in force. The current tax rate is 80 Algerian Dinars (approximately US$ 1) per cubic meter for use of drinking water.

2.7 Flaring

Article 52 HL contains a general prohibition on flaring. However, Article 52 further provides that, in exceptional circumstances and for a limited period of time, ALNAFT may authorise flaring, subject to the payment by the operator to the Treasury of a tax of 8,000 Algerian Dinars (approximately US$ 102) per 1,000 m³ of flared gas. Such tax will not be required to be paid:

- during testing operations on exploration and/or appraisal of wells; and
- during the facilities start-up period, provided such period does not exceed the thresholds set by ALNAFT.

For remote or isolated areas (i.e. areas where infrastructures allowing the recovery and/or export of gas are absent or limited), specific tariffs will be set by regulations.
It is noteworthy that the conditions ALNAFT requires to permit flaring, as well as the admissible thresholds once permission is granted, are not set out in the HL but are to be determined by regulations.

2.8 Economic stabilisation

The HL does not contain any express stability provisions, nor does the exploration and exploitation model contract. In practice, stability provisions are negotiated with ALNAFT and Sonatrach when negotiating the exploration and exploitation contract.

3. Other contractual issues to consider

3.1 Domestic market obligations

There are DMO in Algeria:

- pursuant to Article 51 HL, the gas supply must in priority meet the requirements of the domestic market and ALNAFT may ask each gas producer to contribute to these requirements; and
- in relation to liquid hydrocarbons, Article 50 HL provides that MEM can impose a priority obligation to supply liquid hydrocarbons to the domestic market. If such an obligation is imposed, the MEM specifies the quantities and the duration of the same.

The table below sets out how the HL addresses some of the issues to be considered by IOCs if DMO are applicable:

<table>
<thead>
<tr>
<th>Issues</th>
<th>Algerian Regime</th>
</tr>
</thead>
</table>
| DMO Extent                      | • Maximum rate of contribution from each contractor and the terms and conditions for the supply of gas to the domestic market are defined in the exploration and exploitation contract (Article 51 HL).  
• Supply of gas to Sonatrach will satisfy DMO (Article 51 HL). |
| Shale Gas Exports               | • All exploration and exploitation contracts must contain a joint marketing clause, providing for the joint marketing by Sonatrach and the contractor of any gas to be marketed abroad (Article 48 HL).  
• Sonatrach may market the gas on behalf of the contractor (Article 48 HL). |
| Sale price of gas sold in the domestic market | The price applied is the weighted average, by volume, of the prices of the different Algerian gas export sales contracts of the contractor (Articles 51 and 61 HL). |
| Repatriation of proceeds and profits | Non-resident entities (being entities whose head office is abroad) can repatriate profits (in excess of payment obligations within Algeria) from both domestic and export sales provided that they import the convertible currency needed to cover their exploration and exploitation expenses (Article 55 HL). |
| Definition of domestic market   | "Domestic market" means all the hydrocarbons needed to meet national energy and industrial needs, with the exception of gas for reinjection into fields and for recycling (Article 5 HL). |
3.2 Fiscal regime and tax incentives

There are various taxes applicable to hydrocarbon operations in Algeria. In particular, the contractor must pay:

- a surface rent amount (Article 83 HL);
- a royalty, which can be paid in kind at ALNAFT’s request;
- a Petroleum Revenues Tax (Articles 85, 86, 87 and 88 HL);
- a complementary tax on profits (Article 83 HL);
- a property tax on property other than property used in exploitation as specified by the general tax regime (Article 83 HL);
- a tax on assignment (Article 31 HL);
- a greenhouse gas emission tax (Article 89 HL);
- a water usage tax (Article 53 HL; see above for more details); and
- a flaring tax (Article 52 HL; see above for more details).

Under the HL, contractors benefit from an exemption from VAT, custom taxes and all other taxes not provided for under the HL (Article 89 HL) and, for unconventional hydrocarbons, there is a 20% uplift and an annual investment tranche of 20% (Article 87 HL).

3.3 Third party and state access to infrastructure

Third parties have the right to use:

- pipeline transportation infrastructure (Articles 72 and 79 HL); and
- petroleum products storage infrastructure (Article 79 HL),

on the basis of free access in exchange for payment of a non-discriminatory tariff. The tariffs for the use of pipeline transportation and petroleum products storage infrastructures are determined in accordance with Article 74 HL.

4. Market update

4.1 Recent developments

Currently, Royal Dutch Shell, Eni and Talisman have exploration licences for shale gas exploration in Algeria, with Eni already beginning its exploration phase. Sonatrach has reportedly been in discussion with Gazprom. Anadarko has also expressed an interest in developing shale gas resources in Algeria. In January 2014 it was reported that Exxon Mobil had reached an agreement to begin exploration with an Algerian partner.
4.2 Key shale gas basins

The EIA identified the following basins as having technically recoverable shale gas resources in Algeria:

![Map of Algeria showing shale gas basins]

**Algeria Shale Gas Basins**

Shale gas potential:
- Low
- Medium
- High

4.3 Companies

The following companies are currently involved in shale gas operations in Algeria:

<table>
<thead>
<tr>
<th>Company</th>
<th>Activity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Royal Dutch Shell</td>
<td>Exploration licence.</td>
</tr>
<tr>
<td>Eni</td>
<td>Exploration licence.</td>
</tr>
<tr>
<td>Talisman</td>
<td>Exploration licence.</td>
</tr>
</tbody>
</table>

5. Baker & McKenzie contacts

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South Africa

1. **Introduction**

1.1 **Industry background**

Despite hydrocarbon exploration dating to the middle of the 20th century, South Africa’s deposits of conventional oil and natural gas are very small (0.02 billion barrels proven petroleum reserves and 0.42 tcf proven natural gas reserves). It has therefore relied on its large deposits of coal for most of its energy needs. Natural gas comprises only a small share of South Africa’s energy mix.

Based on EIA estimates, South Africa has 390 tcf of technically recoverable shale gas resources. This has been good news for South Africa given its limited amounts of conventional hydrocarbon supplies. Since South Africa imports around 70% of its crude-oil needs, shale resource discoveries could help it supply its own energy demand and reindustrialise the South African economy.

South Africa lifted its moratorium on fracking and began reviewing new regulations to govern exploration for shale gas in the autumn of 2013. However, South Africa has a large network of conservation groups and a history of green activism which have contributed to a movement against fracking led by a coalition of environmentalists, farmers and local residents. As South Africa looks further into the development of its shale resources it will undoubtedly keep in mind the lessons it learned from the Marikana platinum mine protests in 2012, during which 34 striking workers were shot dead by police.

1.2 **Legal framework**

There is currently no specific legislation for unconventional hydrocarbons in South Africa. Consequently, any shale gas project will fall within the ambit of the Mineral and Petroleum Resources Development Act, 2002 ("MPRDA"), the legislation governing oil and gas exploration and production in South Africa. The MPRDA was recently amended by the Mineral and Petroleum Resources Development Amendment Act, 2008, with certain amendments coming into effect on 13 June 2013.

On 31 May 2013, the South African government published the Mineral and Petroleum Resources Development Amendment Bill ("Bill"), which proposes further amendments to the MPRDA relating, in particular, to state participation and environmental regulations. Finally, on 15 October 2013, the South African government published the draft Technical Regulations for Petroleum Exploration and Exploitation ("Draft Regulations"), which aim to regulate hydraulic fracturing activities.

1.3 **Ownership of hydrocarbon resources**

Pursuant to Section 3 MPRDA, the state is the custodian of all mineral and petroleum resources in South Africa for the benefit of all South Africans. Section 3 MPRDA further provides that “as the custodian of the nation’s mineral and petroleum resources, the state, acting through the Minister, may grant, issue, refuse, control, administer and manage any reconnaissance permission, prospecting right, permission to remove, mining right, mining permit, retention permit, technical co-operation permit, reconnaissance permit, exploration right and production right". In essence, the state is the effective owner of all hydrocarbon resources in South Africa.
1.4 Administration

Administration of Oil & Gas Activities in South Africa

As shown in the schematic above, in South Africa the key regulators and players in the oil and gas sector are:

- **Minister of Mineral Resources** ("Minister"). The Minister is the custodian of South Africa's petroleum resources on behalf of the state. The Minister's roles include, amongst others:
  - responsibility for regulating and promoting mineral and petroleum development in South Africa; and
  - granting or refusing applications for reconnaissance permits, technical co-operation permits, exploration rights and production rights.

- **National Energy Regulator** ("NERSA"). NERSA's role is to:
  - regulate the Piped-Gas and Petroleum Pipeline industries in accordance with the Gas Act, 2001 (Act No. 48 of 2001) ("Gas Act") and Petroleum Pipelines Act, 2003 (Act No. 60 of 2003) ("Petroleum Pipelines Act"); and
  - award licences for the construction and operation of petroleum pipelines, loading facilities and storage facilities.

- **Petroleum Agency South Africa** ("PASA"). PASA promotes exploration for oil and gas resources and their optimal development on behalf of the government. The agency regulates and monitors exploration and production activities and is the custodian of the national exploration and production database for petroleum. PASA is wholly owned by the state through the Central Energy Fund. Pursuant to Section 71 MPRDA, PASA's mandate includes:
  - managing the promotion and licensing of oil and gas exploration, development and production in South Africa;
o receiving applications for reconnaissance permits, technical co-operation permits, exploration rights and production rights, evaluating such applications and making recommendations on the same to the Minister;

o monitoring and reporting regularly to the Minister on compliance with the above permits or rights; and

o reviewing and making recommendations to the Minister with regard to the approval of environmental management plans, environmental management programs, development programs and amendments thereto.

• Minerals and Petroleum Titles Registration Office. The Minerals and Petroleum Titles Registration Office registers exploration and production rights, and maintains records of all reconnaissance and technical co-operation permits.

• Controller of Petroleum Products ("Controller"). The Controller is a statutory authority and its responsibilities include:
   o issuing manufacturing, wholesale, retail and site licences; and
   o investigating offences and gathering information in relation to petroleum products.

2. Key contractual issues for a shale gas project

2.1 Exploration term

Pursuant to Section 80 MPRDA, an exploration right is granted for a term set out in the exploration right, which period may not exceed three years. Section 81 MPRDA provides that an exploration right can be renewed upon application to the Minister for a maximum of three periods not exceeding two years each (i.e. a total maximum exploration term of nine years).

The MPRDA does not set any limit on the size of the area covered by an exploration right.

2.2 Relinquishments

The MPRDA does not currently contain any relinquishment obligations. However, in practice, upon renewal the exploration right holder is required to relinquish:

• on the first renewal, 20% of the exploration area;

• on the second renewal, a further 15% of the exploration area; and

• on the third renewal, a further 15% of the exploration area.

Section 56(b) Bill proposes to insert in the MPRDA an obligation on the exploration and/or production right holder to relinquish a contiguous portion of the area to which the right relates when applying for the renewal of such right, unless the holder proves that it:

• is in a position to explore the entire exploration area; or

• has made a discovery in respect of the entire exploration area.

In addition, please note that it is likely that any exploration right granted for hydraulic fracturing purposes will contain relinquishment obligations.
2.3 Exploitation term

Pursuant to Section 84 MPRDA, a production right is granted for a term set out in the production right, which period may not exceed 30 years. Section 85 MPRDA provides that a production right can be renewed upon application to the Minister for periods not exceeding 30 years each, with no limit being placed on the number of renewals.

The MPRDA does not allow the right holder to continue exploration during the exploitation term (i.e. once a production right is granted, the right to explore falls away).

2.4 Delineation exploitation concession

There are no limits to the size of the area covered by a production right in South Africa.

2.5 NOC participation and carry

Currently, there is no provision for compulsory state participation under the MPRDA. However, PASA's Model Exploration Right and Model Production Right both contain an option for the state to have a maximum participating interest of 10%. Pursuant to the option, the state:

- does not have to pay any amount to exercise the option; and
- will only be required to contribute to its share of the production operations costs but not to exploration or appraisal operations costs.

Section 54(f) Bill proposes to insert in the MPRDA a right for the state "to a free-carried interest in all new exploration rights, with an option to acquire a further interest on specified terms" to be determined by the Minister in the Gazette. Likewise, for production rights, Section 59(d) Bill purports to insert a right for the state "to a free-carried interest in all new production rights, with an option to acquire a further interest on specified terms" to be determined by the Minister. The definition of "free-carried interest" in Section 1(k) Bill implies that the state will not have to contribute to exploration and/or production costs in respect of its free-carried interest. The Bill does not specify the percentage of free-carried interest the state will be entitled to. However, the Minister has announced that the state intends to:

- take a 20% free-carried interest in all new oil and gas projects; and
- reserve the right to buy a further 30% at market-related prices.

In addition, the South African oil and gas industry is required to comply with the Charter for the South African Petroleum and Liquid Fuels Industry on empowering Historically Disadvantaged South Africans which, amongst other things, requires that a 10% participating interest be reserved for Historically Disadvantaged South Africans ("HDSAs"). The Bill provides for compliance with the Amended Broad Based Socio Economic Empowerment Charter for the South African Mining and Minerals Industry. In effect, this means that a 26% participating interest will have to be reserved for HDSAs instead of the current 10%.

2.6 Water resources rights

The Draft Regulations address the protection of water resources. Pursuant to the Draft Regulations, the exploration and/or production right holder will be required to:

- obtain a water use licence in terms of the National Water Act 1998, No. 36 of 1998, stating the term of the water licence. The right holder will have to apply for the water licence at the Department of Water and Environmental Affairs; and
• implement an integrated water use plan and measures to manage and control storm water runoff.

The Draft Regulations provide that, prior to and during all phases of hydraulic fracturing, the operations must:
• not pollute a water resource or reduce a resource;
• not cause an adverse impact on water quality; and
• protect designated and existing water resources.

The Draft Regulations also contain restrictions on the positioning of well sites near water resources and/or any wetlands.

Finally, the Minister of Water and Environmental Affairs has issued a proposal for public comment that hydraulic fracturing be made a "controlled activity" under Section 38 of the National Water Act, No. 36 of 1998. If hydraulic fracturing becomes a "controlled activity" under the Act, the Minister of Water and Environmental Affairs will be able to promulgate further regulations on the same.

2.7 Flaring

Pursuant to the Draft Regulations, the right holder "must minimise emissions associated with venting of hydrocarbon fluids and natural gas during hydraulic fracturing operations". However if it is technically not feasible to do so, the right holder can "capture and direct any natural gas produced during the hydraulic fracturing operations phase to a flare."

The Draft Regulations provide that:
• any flare used must be equipped with a reliable continuous ignition source;
• the right holder must:
  o maintain and operate the flare in accordance with manufacturers’ specifications;
  o file updated site-specific analysis, which contain details about whether any changes have occurred that alter the technical infeasibility of reducing emissions; and
  o report on a quarterly basis the amount of gas flared from each well.

A waste management licence is not required to be obtained for flaring. However, no person may commence, undertake or conduct flaring except in accordance with the standards that have been prescribed by the Minister of Water and Environmental Affairs in terms of the National Environmental Management: Waste Act 2008 ("Standards"). The Standards became part of South African law on 29 November 2013. The Standards:
• provide a regulatory framework on how flaring facilities are prepared, constructed and operated; and
• regulate reporting requirements, training and capacity building, management of emergency situations as well as other general safety requirements.

There are currently no limitations on the amount of gas/oil that can be flared.
2.8 Economic stabilisation

The MPDRA does not address stability. However, the Mineral and Petroleum Resources Royalty Act 28 of 2008, which provides for a royalty on the transfer of mineral resources extracted from South Africa, allows the Minister of Finance to enter into binding fiscal stability agreements with companies active in the extractive industry (which encompass oil and gas companies). These agreements guarantee that the royalty payable by the extractive company will not be increased.

In addition, the Minister of Finance is authorised, pursuant to Schedule 10 to the Income Tax Act 1962, to conclude binding fiscal stability agreements with an oil and gas company. Such fiscal stability agreements are generally transferable.

3. Other contractual issues to consider

3.1 Domestic market obligations

DMO can be imposed by NERSA in South Africa. Pursuant to Section 20 of the Petroleum Pipelines Act, NERSA may impose in any licence an obligation to:

- construct a petroleum pipeline, a loading facility or a storage facility; or
- operate a petroleum pipeline, a loading facility or a storage facility,

and an obligation on the licensee to provide for an appropriate supply of petroleum products to meet South African market requirements.

<table>
<thead>
<tr>
<th>Issues</th>
<th>South African Regime</th>
</tr>
</thead>
<tbody>
<tr>
<td>DMO Extent</td>
<td>The Petroleum Pipelines Act does not stipulate the quantity of gas/oil that can be reserved to meet South African market requirements. This is left to NERSA’s discretion.</td>
</tr>
<tr>
<td>Shale Gas Exports</td>
<td>• Subject to any DMO imposed by NERSA.</td>
</tr>
<tr>
<td></td>
<td>• Gas trading requires a gas licence issued by NERSA pursuant to the Gas Act. Such licence may contain provisions limiting gas exportation.</td>
</tr>
<tr>
<td></td>
<td>• A gas licence is generally granted for a period of 25 years or such longer period as NERSA may determine.</td>
</tr>
<tr>
<td></td>
<td>• The import and export of petroleum products in South Africa is also governed by the International Trade Administration Act No. 71 of 2002 and requires a permit from the International Trade Administration Commission. Export permits are generally valid for a period of six months or less.</td>
</tr>
<tr>
<td>Sale price of gas sold in the domestic market</td>
<td>• NERSA can impose “maximum prices for distributors […] where there is inadequate competition” (Section 21(1)(p) of the Gas Act).</td>
</tr>
<tr>
<td></td>
<td>• NERSA published the Methodology to Approve Maximum Prices of Piped Gas in South Africa in October 2011 (“Methodology”). The Methodology contains a method to calculate the maximum prices of piped gas in South Africa that can be imposed. NERSA does not set prices but reviews maximum piped-gas prices prepared by licensees. NERSA may request licensees or applicants to amend maximum prices or approve such gas prices.</td>
</tr>
<tr>
<td></td>
<td>• Gas destined for export and gas developed offshore is also subject to NERSA’s maximum price/tariff regulation provided it is piped in South Africa.</td>
</tr>
</tbody>
</table>
### Issues

<table>
<thead>
<tr>
<th>Issues</th>
<th>South African Regime</th>
</tr>
</thead>
</table>
| Repatriation of proceeds and profits | • Exchange control regulations, administered by the South African Reserve Bank ("SARB"), govern the movement of financial and real assets into and out of South Africa. SARB has delegated powers to Authorised Dealers (i.e. banks licensed to deal in foreign exchange).  
• Non-residents can freely invest in and disinvest from South Africa (i.e. free repatriation of proceeds and profits).  
• However, exchange control restrictions are imposed for transactions between resident and non-resident. Residents’ outward investments are subject to prior exchange control approval. |
| Definition of domestic market       | There is no definition of "domestic market" provided in the legislation.                                                                                   |

### 3.2 Fiscal regime and tax incentives

A royalty is payable under Section 28 MPRDA by any person who holds an exploration or production right and who extracts and transfers mineral resources (which includes the disposal and consumption of the resources). South African legislation does not provide for a depletion allowance. Tax incentives are as follows:

• corporate income tax rate will not exceed 28%;
• dividend and interest withholding tax of 15% will not apply;
• 200% deduction for capital expenditure for exploration;
• 150% deduction for capital expenditure for production;
• fiscal stability agreements; and
• tax relief on disposal of oil and gas rights.

### 3.3 Third party and state access to infrastructure

Pursuant to Section 21 of the Gas Act and Section 20 of the Petroleum Pipelines Act, when granting a licence for construction and/or operation of a petroleum pipeline, a loading facility or a storage facility, NERSA may require the licensee to grant third parties access on commercially reasonable terms to uncommitted capacity in:

• transmission pipelines; and
• storage facilities.

The state does not have a right of access/use to piped gas infrastructure built in South Africa.
4. Market update

4.1 Recent developments

In September 2012, the government lifted a moratorium that was imposed in April 2011 on shale gas exploration in the Karoo Basin. Shale gas extraction can be undertaken, but it is a controlled activity and therefore requires a water licence that includes an assessment of the effect on groundwater. Proposed regulations on hydraulic fracturing were published in October 2013, which require drillers to meet American Petroleum Standards.

The Minister expects to issue exploration licences for shale gas in the first quarter of 2014. The following companies have applied for shale gas exploration licences for the Karoo from the Department of Mineral Resources: Shell, Challenger Energy subsidiary Bundu Gas & Oil Exploration, Falcon Gas & Oil (in partnership with Chevron), Statoil and Chesapeake.

4.2 Key shale basins

The EIA identified the following basins as having technically recoverable shale gas resources in South Africa:

South Africa Shale Gas Basins

Technically recoverable resources (trillion cubic feet)

390 tcf
4.3 Companies

The following companies are currently involved in shale gas operations in South Africa:

<table>
<thead>
<tr>
<th>Company</th>
<th>Activity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Challenger Energy</td>
<td>Applied for exploration licences.</td>
</tr>
<tr>
<td>Bundu Gas &amp; Oil Exploration</td>
<td>Applied for exploration licences.</td>
</tr>
<tr>
<td>Falcon Gas &amp; Oil (in partnership with Chevron)</td>
<td>Applied for exploration licences.</td>
</tr>
<tr>
<td>Statoil</td>
<td>Applied for exploration licences.</td>
</tr>
<tr>
<td>Chesapeake</td>
<td>Applied for exploration licences.</td>
</tr>
<tr>
<td>Royal Dutch Shell</td>
<td>Applied for exploration licences.</td>
</tr>
</tbody>
</table>

5. Baker & McKenzie contacts

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1. Introduction

Asia Pacific contains significant shale gas reserves, with the EIA ranking China as the country having the most technically recoverable shale gas resources in the world at 1,115 tcf, and Australia, Pakistan and India as having the world's 7th, 15th and 17th largest shale gas resources, respectively. The EIA also highlights Mongolia, Indonesia and Thailand as having significant shale gas resources.

As shown on the map below, with the exception of Thailand, all shale gas-rich countries in the region welcome the development of shale gas. These countries see such development as a way to meet increasing demands for energy while limiting carbon emissions, to increase their energy security and to reduce their oil and gas imports.

2. Key challenges for a shale gas revolution in Asia Pacific

2.1 Geology

Shale reserve geology is highly complex in many Asia Pacific countries. For example, in China's Sichuan basin, shale resources are often three miles deep, which is even deeper than shales
creating hostile conditions in the US (e.g. Haynesville). In addition, these basins are often located near faultlines and have a heavy mud content, so they are anticipated to require more hydraulic horsepower, more advanced fluid chemistry and higher treating pressures than many of the wells in the US. Australia is currently considered more geologically attractive than other countries in Asia Pacific, with geological characteristics similar to those in the US.

2.2 Strong state participation

In most Asia Pacific countries, with the notable exception of Australia, strong state participation requirements have stunted the creation of the open and competitive business environment that is deemed a key factor in the US shale gas revolution. In the US, competition between wildcatters (small and medium-sized risk-taking independent companies) has been integral in ushering in the shale gas revolution. These companies raced to develop and refine methods to economically extract shale resources and to acquire the most promising shale acreages, financed by the availability of cheap credit and joint venture partnerships. In contrast, there is a reticence to open the shale market to foreign companies in some Asia Pacific countries and a tendency to award permits for shale gas exploration and production to state-owned companies. Such state-owned companies are often wary of making the large capital investments required to develop shale in the region.

China is the archetypal example of this attitude. China’s shale production is dominated by two state-owned groups: China National Petroleum Corporation (CNOOC) and Sinopec. State-owned entities and national companies have also prevailed in the two rounds of bidding for the commercial development of shale gas in China. In its attempt to replicate a US-style shale gas revolution, China is dipping its toe into the waters of foreign investment and, in its second bidding round for shale gas, allowed foreign investors to set up joint ventures with Chinese companies to bid for shale gas acreage. However, only two of the winners so far have been privately owned. From a foreign investor’s perspective, this constitutes an inability to conduct business singularly and is another example of China’s lack of an open market.

Indonesia is another Asia Pacific country predisposed to resource nationalism, as exemplified by (1) its February 2012 regulation banning the export of ore/raw materials and requiring mineral processing to be carried out in Indonesia, and (2) its March 2012 ruling that foreign miners sell at least 51% of their Indonesian operations to locals after operating for 10 years (previously they were obliged to sell only 20%, although after five years). In addition, the Indonesian government has recently modified tax benefits for some oil and gas corporations, causing some of them to owe millions of dollars on a retroactive basis, creating a climate of uncertainty over Indonesia’s oil and gas laws. Such uncertainty could deter investment in the country’s shale resources.

2.3 Property rights

Land and intellectual property rights in some Asia Pacific countries will hinder a shale gas revolution. The US’ system of private land and mineral rights ownership allows landowners to sell their mineral rights to independent companies for a slice of the profit the shale reserve produces. In contrast, countries like China, which do not permit private land ownership, have stifled the transfer and leasing of land that allowed the shale industry to flourish in the US.

Most countries in Asia Pacific need technology and know-how to produce shale gas, but their narrow intellectual property rights often limit investment by western companies. China is countering this by fostering "indigenous innovation" meant to produce shale technology to
address the unique challenges associated with Chinese shale reserves, such as their depth and mud content.

3. **Looking forward**

The region’s complex geology, strong state participants and weak property rights will make developing shale resources in Asia Pacific more expensive than developing conventional sources of energy and are likely to restrict the speed of the shale industry’s growth in the region. This has led some commentators to say it will take another five years before significant commercial shale gas production comes online in Asia Pacific, and even longer before the region reaches the level of production seen in the US.

Nevertheless, the production of shale resources holds promise for the region. Australia’s development of its shale resources is expected to be quicker, propelled by an increased energy demand for LNG exports to China (where domestic demand is expected to outstrip shale gas domestic production), India and Japan, as well as Australia’s strong regulatory and institutional frameworks and already-existing infrastructure. Mongolia, hoping to repeat the economic boost its mining development is giving the country, also appears eager to develop its limited shale resources.

4. **Up-and-coming shale countries**

**Asia Pacific Shale Gas Resources**

![Shale Gas Resources Chart]

*Note 1: This graph is based on unproved shale gas technically recoverable resources as per the EIA Report.*
On the basis of the map and graph above, recent regulatory developments, and interest shown by our clients, we have identified Australia and China as the up-and-coming countries for shale gas development in Asia Pacific. The next two chapters will explore how some of the key contractual issues to consider for a shale gas project are addressed in these countries.
Australia

1. Introduction

1.1 Industry background

Whilst Australia’s first recorded oil flow dates to the 1950s, Australia’s oil production has declined overall since 2000 and the country is now a net importer of crude oil. However, its natural gas production has significantly increased over the past decade as a result of new gas field developments. Asia’s demand for cleaner gas-produced energy is driving Australia’s exploitation of its shale resources, and Australia is in the race for second behind the US in bringing significant shale resource production online, with its Cooper Basin being one of the few regions outside of the US currently producing shale gas at commercial levels.

The EIA Report estimates that technically recoverable shale gas resources in Australia are 437 tcf. This is a conservative estimate. Providing a more liberal estimate, the Australian Council of Learned Academies report dated 7 June 2013 titled Securing Australia’s Future concluded that “if all prospective basins are considered, the undiscovered resource could be in excess of 1000 tcf, though the value has a high degree of uncertainty … far more exploration is needed to turn those resource estimates into economic reserves.”

Australia has the capacity to liquify and export its gas via existing and proposed LNG projects. Moreover, in some places infrastructure originally built to serve Australia’s conventional gas and oil production can be used to transport shale gas to the LNG plants.

Companies invest in Australian energy not only because of the demand in Asia but also because of the legal certainty for long-term investments provided by the Australian government in contrast to the uncertainty provided by other governments in the region. However, the advantages of legal certainty in Australia are somewhat counterbalanced by the escalating costs of operations in Australia’s energy sector, along with a shortage of labour. Moreover, companies developing the country’s oil and gas resources are grappling with public opposition in respect of the environmental impacts of oil and gas development, particularly the use of fracking technology in exploration of unconventional gas.

1.2 Legal framework

In Australia, the Offshore Petroleum and Greenhouse Gas Storage Act 2006 (“Cth”) regulates petroleum activities offshore in Commonwealth waters. Each Australian state and territory also has in place laws which regulate gas activities onshore within its territory, or offshore within its territorial waters.

In general, unconventional gas is subject to the same regulatory regime as conventional gas. However, governments have released some laws which apply specifically to exploration of unconventional gas. For example, in 2012 the Standing Council on Energy and Resources (constituted by representatives of the Commonwealth and each State government) released the Draft National Harmonised Regulatory Framework outlining the recommended approach to regulating coal seam gas (“CSG”). In addition, the Commonwealth government and the Queensland (“QLD”), New South Wales (“NSW”), South Australia (“SA”) and Victoria (“VIC”) state governments have entered into a National Partnership Agreement on Coal Seam Gas and Large Mining Development, establishing an Independent Expert Scientific Committee. The Independent Expert Scientific Committee’s role is to advise the signatory states and
Commonwealth governments on large CSG and coal mining development projects likely to impact water resources.

As the shale gas basins identified by the EIA are all onshore, this section will focus on onshore gas legislation. Onshore gas legislation applying in QLD, SA and Western Australia ("WA") (states identified by the EIA as having technically recoverable shale gas reserves), are discussed in this section. Also, legislation applying in NSW, a state currently producing CSG, and VIC, a state currently producing natural gas, are provided as examples for comparative purposes.

**Onshore Regulation of Oil & Gas Activities in Australia**

1.3 Ownership of hydrocarbon resources

In Australia, the ownership of hydrocarbon reserves is vested in the Crown (i.e. Commonwealth, state or territory governments). The rights to explore and produce hydrocarbons are therefore granted through various titles and approvals from the relevant Commonwealth, state or territory authority.
1.4 Administration

Adminstration of Onshore Oil & Gas Activities in Australia

As shown in the schematic above, in Australia the key regulators in the oil and gas sector are:

- **NSW**
  The Division of Resources and Energy ("Division") is part of NSW Department of Trade & Investment. The Division delivers policy, programs and compliance for the NSW government across the minerals and energy sector. In the mineral resources sector, the Division is responsible for facilitating profitable and sustainable mineral resources development, effective environmental management and safe and responsible mining and petroleum production in NSW.

- **QLD**
  The Department of Natural Resources and Mines ("DNRM") is responsible for ensuring Queenslanders benefit from the productive, sustainable use of QLD’s natural resources.
The DNRM also provides support for the safety and health of all QLD miners and people working in allied industries.

• **VIC**

Victoria's mineral, petroleum, extractive and geothermal industries are managed by the Department of State Development, Business and Innovation ("Department"). To ensure sustainability, the Department regulates the industries, promotes the development of the state’s earth resources, maintains the earth resources database and provides scientific and strategic policy advice to government. The Department also provides licensing, monitors environmental standards and supports significant projects.

• **SA**

The Department for Manufacturing, Innovation, Trade, Resources and Energy ("DMITRE") is primarily responsible for promoting the achievement of SA's seven priority areas, which includes:

- realising the benefits of the mining boom for all South Australians; and
- growing advanced manufacturing.

DMITRE is also responsible for:

- attracting private sector exploration investment;
- regulating petroleum and geothermal exploration and development activities;
- providing policy advice to stakeholders on all aspects of petroleum and geothermal resources in SA; and
- managing SA's mineral resources.

• **WA**

The Department of Mines and Petroleum ("DMP") is WA's lead agency in attracting private investment in resource exploration and development through the provision of geoscientific information on minerals and energy resources, and management of an equitable and secure titles system for the mining, petroleum and geothermal industries. DMP also has prime responsibility for regulating these extractive and dangerous goods industries in WA, including the collection of royalties, and ensuring that safety, health and environmental standards are consistent with relevant state and Commonwealth legislation, regulations and policies.

2. **Key contractual issues for a shale gas project**

2.1 **Exploration term**

In NSW, the initial term of an exploration licence is six years, renewable for one further six year term by applying one to two months prior to expiry. There is no express limit on the Minister's power to renew and this will be assessed on an application by application basis.

In QLD, the initial term of the authority to prospect must be for at least the length of the period of the required initial work program as set out in the relevant call for tender, provided that it cannot exceed a maximum of 12 years. Any renewed term must not end more than 12 years from when
the authority to prospect originally took effect. There is no express limit on the Minister's power to renew and this will be assessed on an application by application basis.

In SA, the initial term of an exploration licence is five years. Exploration licences may be renewable for either one or two further terms of five years. Where an exploration licence is renewable, such terms will be specified in the licence when it is granted.

In VIC, the initial term of an exploration licence is five years. This licence can be renewed for one further five year term.

In WA, the initial term of an exploration permit is six years, renewable for one further term of five years by applying within three months of the permit's scheduled expiry.

### Summary of Exploration Terms

<table>
<thead>
<tr>
<th>State</th>
<th>Initial Exploration Term</th>
<th>Renewable</th>
<th>Maximum Exploration Term</th>
</tr>
</thead>
<tbody>
<tr>
<td>NSW</td>
<td>6 years</td>
<td>• Yes</td>
<td>12 years</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• 1 further term of 6 years</td>
<td></td>
</tr>
<tr>
<td>QLD</td>
<td>At least the length of the period required to complete initial work program, but cannot exceed 12 years.</td>
<td>• Yes</td>
<td>12 years</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Renewed term cannot end more than 12 years from grant of initial exploration term</td>
<td></td>
</tr>
<tr>
<td>SA</td>
<td>5 years</td>
<td>• Yes</td>
<td>15 years</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• 1 or two further terms of 5 years</td>
<td></td>
</tr>
<tr>
<td>VIC</td>
<td>5 years</td>
<td>• Yes</td>
<td>10 years</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• 1 further term of 5 years</td>
<td></td>
</tr>
<tr>
<td>WA</td>
<td>5 years</td>
<td>• Yes</td>
<td>10 years</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• 1 further term of 5 years</td>
<td></td>
</tr>
</tbody>
</table>

### 2.2 Relinquishments

In NSW, an exploration licence may only be renewed in respect of an area that is 75% of the size of previous licence (either the original licence or the last previous renewal).

In QLD, there are compulsory relinquishments at the dates set out in the authority to prospect. If the authority to prospect does not specify relinquishment dates, the default date for relinquishment is no later than every four years of the term. On each relinquishment date, at least 8.33% of the authority to prospect's original notional sub-blocks (being the total areas covered by the authority) must be relinquished for each year that has passed since the authority originally took effect. If all of the area of an authority is relinquished, the authority ends.

In SA, a licence holder must relinquish certain quantities of the licence area upon any licence renewal. If the exploration licence can be renewed once, this relinquishment will be an area equal to at least 50% of the original licence area. Where the exploration licence can be renewed twice, the relinquishment will be at least 33.3% of the original licence area upon each renewal.

In WA, a permit holder may be required to relinquish certain quantities of their original permit area upon renewal of that licence, subject to the size of the original permit area. Where the
original permit area is less than four blocks, the renewal application may apply to any or all of that area. Where the original permit area is five or six blocks, the renewal may only apply to up to four of those blocks. Where the original permit area is larger than six blocks, a renewal may only be granted in relation to roughly 50% of the original permit area.

In VIC, upon each renewal of an exploration permit, the permit holder must relinquish 50% of the permit area.

**Summary of Relinquishments Obligations**

<table>
<thead>
<tr>
<th>State</th>
<th>Relinquishment</th>
<th>Acreage to be relinquished</th>
</tr>
</thead>
<tbody>
<tr>
<td>NSW</td>
<td>Yes, compulsory upon any renewal</td>
<td>25% of size of previous licence (either the original licence or the last previous renewal)</td>
</tr>
<tr>
<td>QLD</td>
<td>Yes, compulsory at dates set out in authority to prospect</td>
<td>8.33% of the original notional sub-blocks</td>
</tr>
<tr>
<td></td>
<td>Default date is every 4 years of the term</td>
<td></td>
</tr>
<tr>
<td>SA</td>
<td>Yes, compulsory upon any renewal</td>
<td>• 50% of original permit area if only 1 renewal</td>
</tr>
<tr>
<td></td>
<td>• If more than 1 renewal, 33.3% of original permit area upon each renewal</td>
<td></td>
</tr>
<tr>
<td>VIC</td>
<td>Yes, compulsory upon any renewal</td>
<td>50% of original permit area</td>
</tr>
<tr>
<td>WA</td>
<td>Yes, may be required upon renewal</td>
<td>• None if original permit area is less than 4 blocks</td>
</tr>
<tr>
<td></td>
<td>• 1 or 2 blocks if original permit area is 5 or 6 blocks (i.e. renewal may only apply to 4 blocks)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• 50% of original permit area, if original permit area is larger than 6 blocks</td>
<td></td>
</tr>
</tbody>
</table>

### 2.3 Exploitation term

In NSW, the initial term of a production lease is fixed by the Minister and can be up to 21 years. A production lease can be renewed for a further term by applying one to five years prior to expiry. There is no express limit on the Minister's power to renew and this will be assessed on an application by application basis.

In QLD, both the initial and any renewed term of a petroleum lease must be for at least the duration of the plan set out for the initial development and a maximum of 30 years. After an initial development plan is completed a lease may continue with the lessee filing a later development plan. However, the maximum term of any lease will still be 30 years.

In SA, a production licence may be granted for an unlimited term.

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1 Block is a term used in the legislation to delineate the earth’s land surface into various portions. Further details of the methods involved in quantifying a block are discussed below in Section 2.4 (Delineation exploitation concession).
In VIC, a retention lease\(^2\) will have a term of up to five years. No renewal is permitted for retention leases. The production licence continues in force until it is surrendered or cancelled by the Minister in accordance with the Act.

In WA, the initial term of a production licence will be 21 years. This may be renewed at first for a subsequent period of 21 years and, if a further renewal is approved after these combined 42 years, an indefinite term.

### Summary of Exploitation Terms

<table>
<thead>
<tr>
<th>State</th>
<th>Initial Exploitation Term</th>
<th>Renewable</th>
<th>Maximum Exploitation Term</th>
</tr>
</thead>
<tbody>
<tr>
<td>NSW</td>
<td>21 years</td>
<td>• Yes</td>
<td>42 years, but after that time Minister has power to grant further renewals</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• One further renewal of 21 years</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Minister has power to grant further renewals</td>
<td></td>
</tr>
<tr>
<td>QLD</td>
<td>At least the duration of the plan set out for the initial development and a maximum of 30 years</td>
<td>Yes, provided renewed term cannot end more than 30 years from grant of initial exploitation term</td>
<td>30 years</td>
</tr>
<tr>
<td>SA</td>
<td>N/A</td>
<td>N/A</td>
<td>Unlimited term</td>
</tr>
<tr>
<td>VIC</td>
<td>N/A</td>
<td>N/A</td>
<td>Life of field</td>
</tr>
<tr>
<td>WA</td>
<td>21 years</td>
<td>• Yes</td>
<td>42 years, but after 42 years licence can be extended for an indefinite term</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• One further renewal of 21 years</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>• May be renewed for an indefinite term after 1(^{st}) renewal</td>
<td></td>
</tr>
</tbody>
</table>

### 2.4 Delineation exploitation concession

The exploitation area will be delineated in the production licence/lease. The specific jurisdictional requirements are set out below.

In NSW, pursuant to the Petroleum (Onshore) Act 1991 ("NSW Act"), an exploitation area must not be more than four blocks. A block is a graticular section defined in Section 4 NSW Act as the surface of the Earth taken to be divided:

- by the meridian of Greenwich and by meridians of longitude that are at a distance from that meridian of five minutes, or a multiple of five minutes, of longitude; and
- by the equator and by parallels of latitude that are at a distance from the equator of five minutes, or a multiple of five minutes, of latitude, into graticular sections, each of which is bounded:
  - by portions of two of those meridians that are at a distance from each other of five minutes of longitude; and

\(^2\)A retention lease enables the lease holder to explore and retain title over an area which is not yet commercially viable. Some form of onshore retention lease is available in most jurisdictions. In addition, retention leases are available in offshore oil and gas projects under the Offshore Petroleum and Greenhouse Gas Storage Act 2006.
by portions of two of those parallels that are at a distance from each other of five minutes of latitude.

In effect, these blocks are on average approximately 80 km². However, differences are brought about by the convergence of meridians of longitude between the Equator and the South Pole.

QLD and WA adopt the same delineation of the Earth’s surface into graticular blocks of five minutes by five minutes (for QLD, see Section 29 of the Petroleum and Gas (Production and Safety) Act 2004; for WA, see Section 27 of the Petroleum and Geothermal Energy Resources Act 1967). However, QLD then further delineates each block into sub-blocks resulting from the notional division of a block into 25 areas, each being bounded by two meridians one minute of longitude apart and two parallels of latitude one minute apart. The maximum size of a lease in QLD is 75 sub-blocks (Section 168(8) of the Petroleum and Gas (Production and Safety) Act 2004), while in WA, the maximum is 160 blocks (Sections 30(1) and 50(1) of the Petroleum and Geothermal Energy Resources Act 1967).

Neither SA nor VIC delineate concessions into graticular blocks. The maximum size of a production licence in SA is 1,000 km².

In VIC, the exploitation licence area must be the minimum necessary to cover the maximum extent of the relevant petroleum field or reservoir and enable future petroleum production and storage in relation to the field and future storage in relation to any reservoir.

2.5 NOC participation and carry

There is no required NOC participation in Australia. Foreign investment is generally welcomed in the oil and gas sector. Exploration and development may proceed with 100% foreign interest.

However, a foreign NOC being a state-owned company that proposes to invest in Australia will need to submit an application to the Federal Foreign Investment Review Board ("FIRB") for approval. The FIRB will then make a recommendation to the Federal Treasurer as to whether the proposed investment should be approved and on what terms.

2.6 Water resources rights

Access to and use of water is governed by statutory water rights administered by state and territory governments. Water rights are administered through legal instruments giving one or more water rights and/or permissions to its holder, including water instruments, property titles or contracts with a water service infrastructure operator.

In NSW, the rights to the control, use and flow of water are vested in the Crown, except to the extent that these rights are divested by the Water Management Act 2000 (NSW) Section 392(1) ("WM Act"). There are four different entitlements to water under the WM Act. These are:

- planned environment water under Section 8(1)(a) which has been committed by management plans to fundamental ecosystem health or other specified environmental purposes;
- adaptive environment water which may have conditions imposed upon it under Section 8(1)(b);
- basic landholder rights under Section 52-55; and
- Water Access Licences ("WAL") under Section 56.
Water trading is only envisaged to operate in relation to WAL. There are over 14 categories and 24 sub-categories of WAL provided for in the WM Act and Water Management Regulation 2004. WAL are to be registered at the water access licence register.

In QLD, the rights to use, flow and control of water vest in the state (Section 19 Water Act 2000 ("QLD Water Act")). A person wishing to take water may only do so where authorised under the QLD Water Act. Authorisation may take the form of either a statutory authorisation or a water entitlement. The grant of either statutory authorisations or water entitlements fall within a broad two-stage planning framework which consists of a water resource plan and resource operation plan. Water allocation entitlements are to be registered at the water allocations register.

In VIC, the Crown has the right of primary access (Section 7(1) Water Act 1989 ("VIC Water Act VIC")). The right to take and use water in declared systems is not tied to land, and entitlements can therefore be traded. The VIC Water Act differentiates between:

- water entitlements, which is the maximum amount of water authorised to be taken and used by a person under specific conditions; and
- water allocations, which is the amount of water that can be used under an entitlement in any year.

There are four types of water entitlements under the VIC Water Act:

- bulk entitlements;
- environmental entitlements;
- water shares; and
- water licences.

Water entitlements are to be registered at the Victorian Water register.

In SA, the Natural Resources Management Act 2004 also differentiates between:

- water entitlements - the ongoing right to a specified share of a water resource as set out in a water licence; and
- water allocations - the actual volume of water that may be used within a given period, which may vary from year to year depending on water availability.

Water entitlements set out in a water licence are tradable assets and a licence holder may sell or transfer rights attaching to their entitlement on a permanent or short-term basis. Water entitlements are registered on a Water Register maintained by the Department of Environment, Water and Natural Resources.

In WA, the right to use and flow and to the control of water vests in the Crown (Section 5A Rights in Water and Irrigation Act 1914 (WA)) ("Rights in Water Act"). Under the Rights in Water Act, users may apply for licences and permits allowing access to and use of water from proclaimed water management areas. At present, there are 45 groundwater and 22 surface water management areas which have been proclaimed under the Rights in Water Act. Water licences and permits are registered on the Water Register managed by the Department of Water. Generally, people are entitled to take water from non-proclaimed areas. However, depending on the volume and nature of the use and any conflict which may arise, the Department of Water may take action to regulate usage in such areas.
2.7 Flaring

Generally, flaring must be in accordance with an environmental plan accepted by the applicable state regulator and otherwise in accordance with relevant state laws.

In QLD, pursuant to Sections 72(2) and 151(2) of the Petroleum and Gas (Production and Safety) Act 2004, the title holder must not flare gas unless it is not commercially or technically feasible to use the gas under a lease or for an authorised activity for the lease. There are no restrictions on the quantity of gas one can flare in QLD.

In NSW, SA, VIC and WA, there are no restrictions on the quantity of gas one can flare.

Shale gas extraction activities (including flaring) may attract a unit surrender liability under the Australian government Carbon Pricing Mechanism (“CPM”). The CPM requires that eligible emission units be surrendered to the Clean Energy Regulator in respect of emissions of covered greenhouse gases by facilities which exceed 25,000 tonnes of carbon dioxide equivalent in an Australian financial year (1 July to 30 June). The carbon price payable per tonne of carbon dioxide for the 2013/2014 compliance year is AU$24.15. Failure to surrender units when required attracts a shortfall penalty. Surrender liability for a facility is in the first instance imposed on the entity which has operational control of the facility, but liability can be shared between joint venture partners or transferred within corporate groups or to reflect operation and maintenance or financing arrangements. The operation of the CPM may also result in increased costs for shale gas producers as a result of the pass-through to them of carbon costs embedded in fuel or electricity costs.

Following the September 2013 federal election, the new coalition government has said that it intends to repeal the CPM as soon as possible. This is expected to occur after June 2014. The government has indicated that it plans to replace the CPM with its Direct Action Plan under which the government will purchase emission reduction units from the market. This plan is not currently expected to include legal obligations to surrender units.

2.8 Economic stabilisation

Australian law does not provide for stability provisions.

3. Other contractual issues to consider

3.1 Domestic market obligations

At present, Australia has no DMO at the Federal level. However, in the context of steeply rising prices and tightening domestic demand, industries reliant on gas are increasingly advocating gas reservation policies.

The Energy White Paper 2012, published by the Department of Resources, Energy and Tourism, stated that "the Australian government does not support calls for a national gas reservation policy or other forms of subsidy to effectively maintain separation between domestic and international gas markets or to quarantine gas for domestic supply". Subsequent statements from both major political parties indicate that this view is bipartisan and unlikely to change in the near future.

However, the closure of petrochemical or other gas-intensive business and widespread household dissatisfaction with increasing energy costs could act as political triggers to reignite this policy debate.
At present, two states, QLD and WA, have already adopted regimes for domestic gas reservation (see table below for further details). None of the remaining states has gas reservation policies. In addition, in the last 18 months NSW and the Northern Territory have explicitly rejected calls for domestic reservation policies.

<table>
<thead>
<tr>
<th>Issue</th>
<th>QLD</th>
<th>WA</th>
</tr>
</thead>
<tbody>
<tr>
<td>DMO Extent</td>
<td>DMO obligations are imposed by the Prospective Gas Production Land Reserve Policy, which was implemented under the Gas Security Amendment Act 2011. The policy has yet to be utilised as exports of gas are not scheduled to commence until 2015-17. The policy is only operational where the government's annual Gas Market Review process identifies &quot;domestic supply constraints&quot;. If such constraints are found to exist, the government can create a Prospective Gas Production Land Reserve by placing an Australian Market Supply Condition on future petroleum exploration tenure releases, operating as a condition of tenure under which gas procured from the prescribed land must not be supplied to international markets before domestic demand is exhausted.</td>
<td>Domestic gas reservation regime is not mandated by legislation, but WA has an ongoing policy of requiring all projects to supply 15% of gas produced to domestic consumers in order to gain access to land in WA for the location of gas processing facilities. The policy is flexible and negotiations with companies are conducted on a case-by-case basis to take account of the different characteristics of each project (such as the size and accessibility of the resource, potential markets, appropriate timeframes for delivery, etc.).</td>
</tr>
</tbody>
</table>

Subject to the DMO obligations in QLD and WA set out above, the situation regarding gas export, hydrocarbon prices determination and repatriation of proceeds is as follows in Australia:

<table>
<thead>
<tr>
<th>Issue</th>
<th>Australian Regime</th>
</tr>
</thead>
<tbody>
<tr>
<td>Shale Gas Exports</td>
<td>• There are currently no restrictions on gas exports in Australia.</td>
</tr>
<tr>
<td></td>
<td>• The Energy White Paper 2012 acknowledged that &quot;the emergence of transitional market pressures may particularly affect gas-intensive businesses&quot; but concluded that &quot;responses to those pressures should be consistent with the development of more efficient and flexible gas markets, rather than impose distortionary or constrictive regulation&quot;. This appears to be a bipartisan position.</td>
</tr>
<tr>
<td></td>
<td>• However, the DomGas Alliance of large gas consumers is lobbying for export regulations, arguing that &quot;Australia needs to have sufficiently comprehensive policies and regulations in place in order to control and manage the export of raw commodities&quot; to prevent &quot;the natural resource curse and Dutch disease&quot;.</td>
</tr>
<tr>
<td>Sale price of gas sold in the domestic market</td>
<td>• Unregulated prices for hydrocarbon prevail in Australia.</td>
</tr>
<tr>
<td></td>
<td>• Retail - Since 1 July 2012, the Australian Energy Regulator (&quot;AER&quot;) has taken responsibility for regulation of retail energy markets for certain Australian jurisdictions under the National Energy Customer Framework. The AER does</td>
</tr>
</tbody>
</table>
### Issue vs. Australian Regime

<table>
<thead>
<tr>
<th>Issue</th>
<th>Australian Regime</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>not have a role in setting retail energy prices, and this remains the responsibility of the state and territory governments. However, states and Territories have agreed to phase out the exercise of retail price regulation for natural gas where effective retail competition can be demonstrated. In most states, domestic gas prices are not regulated and are determined by the market price. NSW regulates gas prices for natural gas in respect of standard contract offers to domestic customers by local area retailers. However, customers can also choose to enter into retail supply contracts based on market based prices. In QLD, VIC, WA and SA customers can generally choose between standard retail contracts at the retailer's published standing offer price or market contracts at market based prices.</td>
</tr>
<tr>
<td>Repatriation of proceeds and profits</td>
<td>There are no laws or regulations limiting the repatriation of sales proceeds or profits.</td>
</tr>
</tbody>
</table>

#### 3.2 Fiscal regime and tax incentives

There are no incentives allowed by the states for the resumption/completion of activities on a partially depleted area.

The following taxes are generally payable for oil and gas operations in Australia:

- royalties;
- corporate tax;
- goods and services tax;
- stamp duties; and
- withholding taxes.

Exemptions and incentives vary from state to state.

#### 3.3 Third party and state access to infrastructure

The primary legislation regulating natural gas pipelines is the National Gas Law ("NGL"). It is set out in the Schedule to the National Gas (South Australia) Act 2008 and is given effect by an application act in each other Australian state and territory. The NGL is supplemented by the National Gas Rules ("NGR"). The NGL governs the provision of access to Australia's gas transmission pipelines. The NGL replaced the Gas Pipelines Access Law (including the National Third Party Access Code for Natural Gas Pipeline Systems) ("Code") which previously regulated pipeline services throughout Australia.

The National Competition Council ("NCC") will make a recommendation to the relevant Minister in the state or territory jurisdiction, as to whether a pipeline should be subject to coverage.

---

3 This is a decision about whether a particular pipeline will be subject to an access arrangement and in what form.
Pipelines that are subject to a coverage decision are referred to as covered pipelines, and pipelines that are not as uncovered pipelines.

3.3.1 Uncovered pipelines

Economic regulation does not apply to uncovered pipelines. There is a possibility that an uncovered pipeline may be subject to a pipeline application, which could result in a determination that the pipeline will be covered. This process is discussed below.

3.3.2 Covered pipelines

The NGL only applies access regulation to covered pipelines. A pipeline may be covered under the NGL in the following ways:

- under the Code - pipelines which were covered pipelines under the Code are deemed to be covered pipelines;
- determination - a person may apply under the NGL to the NCC for a determination that a particular pipeline should be a covered pipeline. For an application for coverage to be successful, it must meet the criteria for coverage prescribed under the NGL. This criteria involves consideration of the following factors:
  - whether access to the pipeline services provided would increase competition in at least one market;
  - whether it would be uneconomical for anyone to develop another pipeline to provide the pipeline services provided by means of the pipeline;
  - whether access could be provided without undue risk to human health or safety; and
  - whether access would not be contrary to the public interest;
- if the NCC considers that the access application satisfies all of the above pipeline coverage criteria, it must recommend to the relevant Minister that the pipeline should be covered. On receiving a coverage recommendation from the NCC, if the Minister agrees with the NCC that the pipeline access coverage criteria are satisfied, it must make a determination that the pipeline is covered. In making this determination it must give regard to the national gas objective and any submissions received, in addition to the NCC’s recommendation;
- tender approval pipelines - a pipeline will be covered where a service provider has been awarded a tender to construct and operate a pipeline as a result of a tender approval process which was approved under the NGR; and
- voluntary access arrangement - a pipeline will be covered where a service provider voluntarily submits a full access arrangement to the regulator and the regulator approves that voluntary access arrangement.

Covered pipelines will be determined to be subject to either full regulation or light regulation. These two types of regulations are described below.

3.3.3 Full regulation

A fully regulated pipeline must have a full access arrangement approved by the AER. The access arrangement must contain price and revenue terms and other (non-price) terms and conditions of access for reference services provided by the pipeline, such as obligations
regarding system use gas, linepack, overruns, gas quality and metering. Access arrangements for transmission pipelines must include requirements relating to:

- queuing procedures (providing an order of priority between prospective users of spare or developable capacity);
- extensions of or expansions to a pipeline;
- trading of capacity and changing receipt; and
- delivery points.

The process of approving an access arrangement includes a pre-submission conference with the AER, service provider submission of a proposed access arrangement, public consultation and the public release of draft and final determinations within prescribed timeframes (rules 56 - 64, NGR). A separate decision making process applies when varying an existing access arrangement and differs according to whether the variation is material or non-material (rules 65 - 67 NGR).

Full access arrangements must have a review date (usually four years with the revision commencing in five years) and are not permitted to have an expiry date. The access arrangement may also specify trigger events for review.

### 3.3.4 Light regulation

The NGL provides for "light handed" regulation for certain covered pipelines, in circumstances where the NCC considers that light regulation is sufficient to constrain the service provider given its market power. Light regulation is considered particularly relevant for point-to-point transmission pipelines with a small number of users who have countervailing market power. A service provider under light regulation will not be subject to price regulation but must publish its prices and other terms and conditions of access to its services and is prohibited from engaging in discrimination for its services. Such service provider must also report on access negotiations to the regulator and is subject to arbitration under the access dispute provisions of the NGL. It may (at its discretion) submit a limited access arrangement to the AER for approval. Such arrangement is not required to make provisions for price terms, but must contain non-price terms of access.

The decision making framework for assessing a limited access arrangement is the expedited process set out in the NGR (rules 9, 55 and 130), involving a pre-submission consultation, proposal submission, consultation process, and public release of draft and final determinations within prescribed timeframes.

Light access arrangements may have a specified review date and/or include trigger events for review.

### 4. Market update

#### 4.1 Recent developments

Recent activity in the Cooper (SA) and Canning (WA) Basins has emphasised the ongoing commercial interest in the development of Australian shale gas reserves.

In the Cooper Basin:
in October 2012, Santos announced that it had commenced commercial natural gas production at a stabilised rate of 2.7 mmscf/d from its Moomba-191 shale well;

• in May 2013, Chevron entered into a farm-in agreement with Beach Energy to acquire a 60% interest in PEL 218 and 36% interest in ATP 855, at an initial outlay of US$ 201 million followed by a further US$ 125 million in stage two;

• in September 2013, junior explorer Drillsearch commenced drilling on a four well shale gas and tight sands drilling program in joint venture with QGC (BG). The program will be drilled over 2014; and

• in January 2014, Santos announced it had successfully brought Australia’s second well, Moomba-194, into shale gas production.

Gas produced from the Cooper Basin has been earmarked as a potential source of gas for the various LNG projects in QLD’s Gladstone region.

In the Canning Basin:

• in November 2012, the WA government entered into a 25 year natural gas agreement with Buru Energy and Mitsubishi Corporation over their unconventional gas exploration program in the Basin; and

• in February 2013, PetroChina Company Limited ("PetroChina") entered into a farm-in agreement with ConocoPhillips to acquire a 29% interest in the Goldwyer shale project, stated to contain 229 tcf of recoverable gases.

In December 2012, South Australia released its Roadmap for Unconventional Gas Projects in South Australia, promoting cautious optimism regarding shale gas opportunities. In addition, on 21 November 2013, the Victorian government extended its moratorium on fracking until July 2015 (the same day that it released the Reith Report into the state’s gas market calling for the ban to be lifted). Premier Napthine stated that his government would pass legislation banning the use of benzene, toluene, ethylbenzene and xylene, chemicals that are sometimes used in fracking.
4.2 Key shale basins

The EIA identified the following basins as having technically recoverable shale gas resources in Australia:

**Australia Shale Gas Basins**

The Cooper Basin appears to be the most commercially viable region for shale gas development in Australia due to the ready access to infrastructure including the extensive pipeline and compression network supplying gas to the rest of the "Eastern Market" (i.e. SA, NSW, VIC and QLD).

The Canning Basin is also the subject of interest from major IOCs. However, its distance from markets, low population density and limited road network, as well as the absence of any pipeline network, mean that it will require significant discoveries to underpin the necessary infrastructure.
4.3 Companies

The following companies are currently involved in shale gas operations in Australia:

<table>
<thead>
<tr>
<th>Company</th>
<th>Activity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Beach Energy, Chevron, Senex, Strike Energy, Drillsearch, Santos</td>
<td>Successful exploration in the Cooper basin. Beach Energy and Santos now in the production phase.</td>
</tr>
<tr>
<td>Conoco Philips, HESS Corporation, Buru Energy, Mitsubishi Corp, PetroChina, Strata-X, Apache, Falcon Oil and Gas</td>
<td>Interests in the Canning basin.</td>
</tr>
<tr>
<td>Total, Petro Frontier, Statoil</td>
<td>Interests in the Georgia basin.</td>
</tr>
</tbody>
</table>

5. Baker & McKenzie contacts

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China

1. Introduction

1.1 Industry background

China's economic boom has outstripped its oil supply, leading the country to become the world's biggest net importer of oil. To balance its reliance on foreign countries for oil, China is investing in its national oil reserves and acquiring oilfields overseas. Although natural gas accounts for a relatively small portion of the country's total primary energy consumption, China is also experiencing a natural gas shortage because its domestic supply cannot meet demand.

State-owned oil and gas companies like China National Offshore Oil Corp. ("CNOOC"), China National Petroleum Corp. ("CNPC") and China Petrochemical Corporation ("Sinopec") dominate China's oil and gas industry. They are currently seeking to acquire the technological expertise necessary to develop China's shale resources, estimated to be the largest in the world, by entering into joint ventures with foreign companies on oil and gas projects both in China and abroad. This has led China to become slightly more encouraging of foreign investment into China's energy sector.

Nevertheless, direct investment in China's shale exploration and extraction rights seemingly remains off-limits, with all the exploration blocks in the first few shale gas bids awarded to Chinese companies. In addition, drilling for shale resources in China is expected to be complicated by China's difficult underground geology, lack of water and lack of infrastructure to transport gas to major cities.

1.2 Legal framework

As shale gas has been identified by the Chinese authorities as a new type of mineral resource, it is subject to a separate legal regime from conventional oil and gas. To date, a clear regulatory framework and detailed regulations for shale gas are lacking. However, Chinese authorities have started to build on the existing regulatory system by issuing some regulations and policy statements in relation to shale resources.

On 26 October 2012, the Ministry of Land and Resources ("MOLAR") issued a Notice Regarding the Strengthening of Shale Gas Exploration, Prospecting, Supervision and Administration ("Notice"). The Notice is effective for five years. It spells out in broad terms the requirements and guidance of MOLAR for establishing and granting shale gas exploration rights and exploitation rights, as well as for the exploration and exploitation activities of the right holders. In particular, the Notice gives existing holders of conventional oil and gas mining rights three months from the date of its issuance to apply to MOLAR for amendment of their mining rights, to include shale gas deposits located in the blocks covered by such mining rights. It further provides that failure to apply for such amendment may result in MOLAR granting mining rights over such shale gas deposits to new applicants. The Notice also requires an exploration right applicant to provide MOLAR with an undertaking as to its investment amount, work commitments, work progress, relinquishment, liability for breach and similar matters. This requirement applies both to amendments of existing licences (to add shale gas) and grants of new licences through bidding rounds.
On 30 October 2013, the National Energy Administration ("NEA"), which is part of the National Development and Reform Commission ("NDRC") and regulates the energy sector, issued a Shale Gas Industry Policy ("Policy"). The Policy contains, among other things, general principles on industry regulation and policies on industry technologies, markets, transportation, energy conservation, environmental protection and fiscal support. For example, the Policy encourages diversified investors (including private companies) to invest in shale gas exploration and development and requires market pricing of shale gas "ex-works". The Policy also encourages Chinese companies engaged in shale gas exploration or development to cooperate with "foreign entities with advanced shale gas technologies" in order to bring to China their shale gas exploration and development technologies as well as their production and management expertise. The Policy classifies shale gas as a "national strategic new industry" and calls for more fiscal support of exploration and development of shale gas.

Although the Notice and the Policy have filled part of the shale gas regulatory framework void in China, many gaps still exist. In this respect, both the Notice and the Policy state that the regulations on conventional oil and gas should be referred to for matters which are not specifically addressed in the Notice, the Policy or any other shale gas regulations.

1.3 Ownership of hydrocarbon resources

Under China's Constitution and the Property Rights Law of the People's Republic of China promulgated on 16 March 2007, all minerals (including hydrocarbons) are owned by the state. However, this law allows companies (including state-owned enterprises and privately owned companies) to obtain mining exploration rights and mining exploitation rights in compliance with the requirements of relevant laws and regulations.

1.4 Administration

Administration of Shale Gas Activities in China

As shown in the schematic above, in China the principal regulators for shale gas are:
• **NDRC and NEA.** The NDRC and the NEA regulate the energy sector and take the lead in setting industry policy and framing the regulatory system. The NDRC is also the authority in charge of energy pricing. However, it has stated it will allow the market to play a major role in setting the price of shale gas.

• **MOLAR.** MOLAR is in charge of issuing and registering mining exploration and exploitation licences for shale gas. To date, it has organised two bidding rounds for shale gas exploration licences in each of 2011 and 2012. It is planning a third round likely to be held in 2014. MOLAR is also in charge of approving the shale gas blocks which will be available for cooperation between foreign and Chinese companies.

• **The Ministry of Finance ("MOF").** MOF is the authority that works with NDRC to set and implement the fiscal policy for shale gas, including tax and other incentives for shale gas exploration and exploitation.

• **Ministry of Commerce ("MOFCOM").** MOFCOM is the authority working with NDRC to regulate foreign investment in shale gas exploration and exploitation. It is in charge of the registration of co-operation agreements between Chinese and foreign partners.

• **Other authorities.** Other key regulators for shale gas are the State Administration of Foreign Exchange ("SAFE"), the State Administration of Taxation, the General Customs Office, the Ministry of Water Resources and the Ministry of Environmental Protection.

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2. **Key contractual issues for a shale gas project**

2.1 **Mining rights**

Under Chinese law, mining rights are classified into exploration rights and exploitation rights. For shale gas, the Notice states MOLAR will grant shale gas exploration licences mainly by way of public bidding. One notable exception is the first batch of shale gas licences granted to holders of existing conventional oil and gas licences who were able to acquire a shale gas licence simply by applying for an amendment of their existing licences.

Pursuant to the Notice and MOLAR’s qualification requirements in previous bidding rounds for shale gas exploration licences, only domestic companies owned by Chinese or Sino-foreign joint ventures controlled by Chinese companies can obtain shale gas licences. Foreign companies or their wholly-owned or controlled subsidiaries in China are excluded from the bidding process. Instead, they are encouraged to participate in shale gas exploration and development by partnering with Chinese companies that hold shale gas licences. However, the Notices and the Policy do not specifically address how such partnerships are to be set up. By analogy to the existing regulations applicable to conventional oil and gas, in particular, the Regulation on Sino-foreign Co-operation in Exploitation of Onshore Petroleum Resources ("Onshore Petroleum Regulation"), it is likely that any Sino-foreign co-operation for shale gas will need to go through the following steps:

1) MOLAR will need to delineate certain blocks open for international co-operation. In general, a Chinese company (i.e. a NOC) would take the initiative to apply to MOLAR for opening one or more of their blocks for Sino-foreign development. If MOLAR approves the application, then the relevant blocks will be open for international co-operation;

2) the Chinese company will select the international company it will work with. For onshore petroleum projects, the Chinese company can decide whether to go through a tendering
process or to engage via direct negotiation. The chosen international company will then negotiate and enter into a production sharing contract ("PSC") with the Chinese company;

3) the Chinese company will apply to MOLAR for a Foreign Co-operation Permit by presenting the requested supporting documents, which include the signed PSC; and

4) the Chinese company will file a notice regarding the signed PSC to MOFCOM. Until May 2013, a formal approval by MOFCOM of the PSC was needed. At present, notification is sufficient.

According to industry practice, prior to entering into a PSC and obtaining a Foreign Co-operation Permit, the Chinese company and the foreign company may enter into a joint study agreement ("JSA") for the purpose of assessing the development potential of a shale gas block. Such JSA is also required to be registered with MOFCOM.

2.2 Exploration term

There are no regulations specifying the exploration term for shale gas. In the previous bidding rounds organised by MOLAR, the exploration term was fixed at three years, which is in line with the term of an exploration licence for minerals other than oil and gas. Therefore, it seems to reflect MOLAR's position that shale gas should be treated as a general mineral rather than conventional oil and gas in this respect.

The term of an exploration licence for conventional oil and gas is a maximum of seven years. As for renewals, under current regulations, the term of an exploration licence may be renewed an unlimited number of times and each renewal is for a period of no more than two years.

2.3 Relinquishments

The Notice requires applicants for shale gas exploration licences to make commitments regarding relinquishments. However, it is not clear what kind of commitments are expected. In addition, some local regulations contain mandatory relinquishments that may be applicable to shale gas. It should also be noted that the Shale Gas Development Plan (2011-2015) jointly issued by NDRC, MOLAR and NEA in March 2012 expressly calls for "strengthening the block relinquishment mechanism" when establishing a regulatory framework for shale gas.

2.4 Exploitation term

There are no regulations specifying the exploitation term for shale gas. Under the relevant regulations, the term of a exploitation licence is no more than 30 years for "large-size" mines, 20 years for "mid-size" mines, and 10 years for "small-size" mines. For hydrocarbon gas and coal-bed methane, a mine with a production capacity of 500 million cubic metres or above is a large-size mine, a mine with a production capacity between 100 million cubic metres and 500 million cubic metres is a mid-size mine, and a mine with a production capacity below 100 million cubic metres is a small-size mine. The exploitation term may be renewed upon expiry, and there is no limitation of the term on such renewal. As there are no regulations specifying the exploitation term for shale gas, the regulation currently applicable for hydrocarbon gas and coal-bed methane is likely to apply to shale gas deposits.

2.5 Delineation exploitation concession

Under the relevant regulations, the applicant for an exploitation licence must submit to MOLAR or its local counterparts an approved Ecological Prospecting and Reserve Report for the delineation of the exploitation area. A map of such exploitation area must be included as part of
the application documents for an exploitation licence. Following the issuance of an exploitation licence, the local government will announce the exploitation area and, at the request of the licence holder, place physical boundaries or other surface markings around the exploitation area.

2.6 NOC participation and carry

According to the Onshore Petroleum Regulations, and unless otherwise provided by laws and regulations or agreed in a Sino-foreign co-operation agreement, the foreign company will solely bear the costs of and undertake the relevant exploration operations. The Chinese NOC will only contribute to the costs at the development stage (i.e. once a field has been found commercially exploitable). The foreign company may recover the share of the NOC’s exploration investments and expenses it advanced from its share of the production under the co-operation agreement. The same principles will likely apply to Sino-foreign co-operation for shale gas exploration and development. In essence, the extent of the NOC carry is not regulated by law and is purely a matter of commercial negotiation between the NOC and the foreign company.

2.7 Water resources rights

Under the general laws and regulations applicable to oil and gas operations, the construction and usage of water engineering projects or facilities to extract water from rivers, lakes or underground water is subject to obtaining a water use licence from the water administration authority (currently the Ministry of Water Resources or its local counterpart) and payment of water resource fees. The Policy and the Notice do not contain special rules on water resources rights for shale gas but require that shale gas exploration and developments shall adopt measures for water conservation, recycling of drilling fluids and fracturing fluids, and avoidance of underground water pollution.

2.8 Flaring

There are currently no Chinese laws or regulations that prohibit or restrict gas flaring.

2.9 Economic stabilisation

The current regulations do not contain any provision to address the stabilisation of shale gas interests of foreign investors. However, it is not uncommon for PSCs relating to conventional oil and gas to contain a form of economic rebalancing mechanism. Such mechanism provides that, if a material change occurs to the foreign company’s economic benefits after the effective date of the PSC due to a change in law, the parties shall consult promptly and make necessary revisions and adjustments to the relevant provisions of the PSC in order to maintain the foreign company’s normal and reasonable economic benefits thereunder.

3. Other contractual issues to consider

3.1 Domestic market obligations

Chinese laws and regulations do not impose DMO on foreign investors in oil and gas projects. Indeed, Article 15 of the Onshore Petroleum Regulations expressly provides that a foreign investor may export outside China the petroleum it received from production under a co-operation agreement. However, it is arguable that there is a de facto DMO in China as most PSCs require that petroleum be sold to the Chinese partner. The table below therefore sets out some key provisions to consider when such de facto DMO applies:
3.2 Fiscal regime and tax incentives

The latest version of the Foreign Investment Industry Guidance Catalogue ("Catalogue"), which took effect on 30 January 2012, specifies that foreign investments in shale gas and shale oil exploration and development fall in the "encouraged" category of the Catalogue. This permits foreign investors to set up joint ventures with their Chinese partners and to enjoy certain administrative, fiscal and tax benefits. For example, under current regulations, foreign investment projects in the encouraged category, provided foreign investments do not exceed US$ 300 million, are subject to local government approval (which is often faster than the central government approval process). This is not the case for projects in the "restricted" category which must be submitted to the central government if the total amount of investment exceeds US$ 50 million. In addition, for foreign investment projects falling in the "encouraged" category, the relevant entity is entitled to an exemption from tariff and import value-added tax on importation of any "self-used equipment and associated technology".

In November 2012, as part of its efforts to incentivise the development of domestic shale gas, MOF and NEA jointly issued fiscal incentives providing for a subsidy of RMB 0.4/m³, or US$ 0.06/m³, for shale gas produced from 2012 to 2015. The value of the subsidy given to companies will be "adjusted" from time to time to reflect the industry's development. Local governments will manage the level of fiscal incentive granted regionally.

In addition to direct subsidies, the Policy calls for the reduction of mining resources taxes and mining royalties, and for tax incentives in relation to resources tax, VAT and income taxes. However, it is not clear when these tax initiatives will be implemented.

In March 2013, officials from MOLAR suggested that more policies to support shale gas development will be implemented. These will address the "technology, research and infrastructure aspects" of shale gas development. More stringent environmental standards are likely to be put in place, but the market could also be further opened to enhance competition.

3.3 Third party and state access to infrastructure

Chinese legislation does not address this issue. The only solution available to a foreign investor is to ensure that access rights are included in the PSC it signs with its Chinese partner and that such Chinese partner owns the necessary pipeline and ancillary infrastructure (or has access to it).
4. Market update

4.1 Recent developments

China’s 12th Five-Year Plan, endorsed by National People's Congress on 14 March 2011, lays out an overall target and four milestones for shale gas development to be achieved by China between 2011 and 2015:

- completing a nationwide shale gas survey and appraisal;
- reaching a production output of 6.5 billion cubic metres by 2015;
- developing appropriate methods, technologies and equipment for China’s shale gas survey, appraisal, exploration and production; and
- establishing technical standards, rules and policies regulating the following activities in relation to shale gas projects:
  - reserve survey, appraisal and certification;
  - test and analysis;
  - exploration and production; and
  - environmental measurements.

Two bidding rounds for commercial development of shale gas in China were tendered by MOLAR in 2011 and 2012 respectively. There were discussions about a third bidding round in 2013 but this round did not take place. It is unclear when the third round will take place, but rumours are that it is likely to be in 2014.

The second licensing round attracted 152 bids from 83 companies for 20 blocks, with many of the bids offering 10 times the minimum investment required. Many of the bidders were non-traditional players, such as mining companies and utilities, which are seeking to take positions for the expected Chinese shale gas boom. The bidders included:

- oilfield services player Honghua Group;
- domestic mining giant China Shenhua Energy; and
- utility China Huadian Corporation’s subsidiary Guizhou Wujiang Hydropower Development.

Except for two private Chinese companies in the second round, the successful bidders were state-owned companies in the power generation or coal mining industry.

The level of interest and early results suggest that shale gas exploration activity will be high. This bodes well for China as greater exploration will help the country understand its geological profile and build up domestic expertise in this area, two issues that MOLAR had highlighted as some of the biggest challenges to commercialising its shale resources.
4.2 Key shale basins

The EIA identified the following basins as having technically recoverable shale gas resources in China:

4.3 Companies

China’s NOCs are currently taking the lead in developing its shale gas assets. For instance:

- CNPC is one of the dominant players in China’s shale gas sector. In March 2012, CNPC and Shell signed the first PSC for shale gas in China, which was approved by the Chinese government in March 2013. It is reported that CNPC made a technological breakthrough in the technology for horizontal fracturing and successfully tested its new technology in two shale gas blocks in Southwest China. By January 2013, CNPC had drilled around 12 gas wells and gathered around 12.9 million cubic metres shale gas from its Southwest oil and gas fields;

- CNOOC announced on 12 January 2012 that it had started drilling at its first domestic shale gas project in Anhui Province. Exploration is taking place across a 4,800 km² block in Wuhu City; and
• Sinopec also launched its first shale gas project in the Fuling block, located in Chongqing in May 2012. The production capacity of the project is 500 million cubic metres currently and is projected to reach 5 bcm in 2015. In October 2012, Sinopec officially started work on the block after obtaining favourable gas flows from the Fushi-1 well, which hit 126,000 m³ per day during testing. No concrete development plans have been announced. However, PetroChina expects to produce at least 1.5 billion cubic metres in shale gas by 2015.

China’s shale gas potential, combined with its large domestic market, has also attracted foreign firms:

• Royal Dutch Shell has taken the lead among major IOCs, signing China’s first shale gas PSC for the Fushun-Yongchuan block in the Sichuan basin. It is planning to spend US$ 1 billion per year to develop shale gas resources in the country; and

• other prominent IOCs involved in China include ExxonMobil, Chevron, ConocoPhillips and Eni. ConocoPhillips and Eni have entered into JSAs with PetroChina and its parent company CNPC as part of overseas farm-in deals. These can be converted into PSCs if commercial discoveries are made during exploration.

<table>
<thead>
<tr>
<th>Date</th>
<th>IOC</th>
<th>NOC</th>
<th>Block</th>
<th>Location</th>
<th>Area (km²)</th>
<th>Agreement</th>
</tr>
</thead>
<tbody>
<tr>
<td>October 2007</td>
<td>Newfield Exploration</td>
<td>CNPC</td>
<td>Weiyuan</td>
<td>Sichuan</td>
<td>No information</td>
<td>JSA (completed in 2008)</td>
</tr>
<tr>
<td>January 2010</td>
<td>BP</td>
<td>Sinopec</td>
<td>Kaili, Guizhou; Huangqiao</td>
<td>Jiangsu</td>
<td>No information</td>
<td>JSA</td>
</tr>
<tr>
<td>March 2010</td>
<td>Royal Dutch Shell</td>
<td>CNPC</td>
<td>Jinqui</td>
<td>Sichuan</td>
<td>No information</td>
<td>PSC</td>
</tr>
<tr>
<td>March 2011</td>
<td>Total S.A</td>
<td>CNPC</td>
<td>No information</td>
<td>Sulige South, Inner Mongolia</td>
<td>No information</td>
<td>A joint venture has been set up for natural gas exploitation. Shale gas was found in the block. The parties agreed the joint venture company would be in charge of the shale gas exploration and exploitation. The joint venture is currently awaiting government approval.</td>
</tr>
<tr>
<td>April 2011</td>
<td>Chevron</td>
<td>Sinopec</td>
<td>No information</td>
<td>Qiannan</td>
<td>No information</td>
<td>JSA</td>
</tr>
<tr>
<td>Date</td>
<td>IOC</td>
<td>NOC</td>
<td>Block</td>
<td>Location</td>
<td>Area (km²)</td>
<td>Agreement</td>
</tr>
<tr>
<td>------------</td>
<td>----------------------</td>
<td>----------</td>
<td>------------------------------</td>
<td>----------</td>
<td>------------</td>
<td>------------------------</td>
</tr>
<tr>
<td>July 2011</td>
<td>ExxonMobil</td>
<td>Sinopec</td>
<td>Wuzhishan</td>
<td>Sichuan</td>
<td>3,643</td>
<td>JSA</td>
</tr>
<tr>
<td>January 2012</td>
<td>Royal Dutch Shell</td>
<td>CNOOC</td>
<td>no information</td>
<td>Anhui</td>
<td>4,800</td>
<td>JSA</td>
</tr>
<tr>
<td>March 2012</td>
<td>Royal Dutch Shell</td>
<td>CNPC</td>
<td>Fushun-Yonchuan</td>
<td>Sichuan</td>
<td>3,500</td>
<td>PSC</td>
</tr>
<tr>
<td>May 2012</td>
<td>No information</td>
<td>Sinopec</td>
<td>Fuling</td>
<td>Sichuan</td>
<td>No information</td>
<td>No information</td>
</tr>
<tr>
<td>December 2012</td>
<td>Royal Dutch Shell</td>
<td>CNPC</td>
<td>Zitong block</td>
<td>Sichuan</td>
<td>No information</td>
<td>PSC</td>
</tr>
<tr>
<td>December 2012</td>
<td>ConocoPhilips</td>
<td>Sinopec</td>
<td>Qijiang</td>
<td>Sichuan</td>
<td>3,917</td>
<td>JSA</td>
</tr>
<tr>
<td>December 2012</td>
<td>Baker Hughes</td>
<td>Honghua Group</td>
<td>Research centre in Chengdu</td>
<td>Sichuan</td>
<td>No information</td>
<td>Unconventional gas research and engineering services</td>
</tr>
<tr>
<td>February 2013</td>
<td>ConocoPhilips</td>
<td>CNPC</td>
<td>Neijiang-Dazu</td>
<td>Sichuan</td>
<td>2,023</td>
<td>JSA</td>
</tr>
<tr>
<td>March 2013</td>
<td>ENI</td>
<td>CNPC</td>
<td>Rongchang</td>
<td>Sichuan</td>
<td>2,000</td>
<td>JSA</td>
</tr>
<tr>
<td>March 2013</td>
<td>Total S.A</td>
<td>Sinopec</td>
<td>Xuancheng-Tonglu</td>
<td>Anhui province</td>
<td>No information</td>
<td>JSA</td>
</tr>
</tbody>
</table>

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CIS

1. Introduction

Russia leads the pack for recoverable shale resources in the Commonwealth of Independent States ("CIS") with 287 tcf of technically recoverable resources, followed by Ukraine with 128 tcf. Whilst Ukraine, as depicted below, has embraced the development of its shale resources, Russia is taking a more cautious approach. These two countries’ different attitudes to shale gas can, in part, be explained by their current energy needs and supplies. For Russia, a major conventional oil and gas producer (80 billion barrels proven oil reserves and 1,688 tcf proven natural gas reserves), it is more cost efficient to develop its conventional resources. Ukraine, on the other hand, which imports 75% of its gas consumption from Turkmenistan and Russia, is eager to reduce its energy dependency and its energy costs by developing its shale gas resources. The extent of shale resources in other CIS countries is unknown.

CIS: Shale Gas Reserves and Policy Approaches

2. Key challenges for a shale gas revolution in the CIS

2.1 The great unknown

Besides Russia and Ukraine, around 8.8 billion tonnes of oil shale, 3.6 billion tonnes of which are thought to constitute recoverable reserves, are estimated to be located in Belarus’ Pripyat Shale Basin, occupying western Homiel, southern Minsk and eastern Brest voblasts. However, these reserves remain unexplored due to their complex geology of high ash and sulphur content and
the reserves’ low heat of combustion. The Belarusian industrial group Belorusneft and the British company Toros plan to set up a joint venture to prospect and possibly extract shale oil and shale gas in this Pripyat Shale Basin.

Moldova is also thought to have substantial shallow depth shale gas deposits along its border with Ukraine. In addition, it has been reported that a US$ 600 million project in Uzbekistan has begun drilling for oil shale at the Sangruntau deposit in northern Navoi Region. However, as most CIS countries have been subject to only limited or no exploration of their shale gas potential, these estimated resources are mere conjectures and these countries will have to acquire additional data before considering a potential shale revolution.

2.2 Economic unfeasibility

Many of the CIS countries, with the notable exception of Russia, do not have the funds to cover the high cost of exploring, extracting and processing shale resources. Moreover, their often unstable governments (with the exception of Ukraine, which has recently signed deals for shale gas exploration with Chevron and Royal Dutch Shell) are not as easily able to attract the level of foreign investment necessary to explore and extract shale resources.

Russia is testing its shale reserves in some places. For example, in December 2013 Rosneft and Statoil signed a shareholders and operating agreement for a joint venture to assess the feasibility of commercial production from the Domanik shale formation in Samara.

3. Looking forward

It is presumed that most CIS countries would like to have their own shale gas revolution in order to experience some of the economic benefits seen in the US and diversify their energy sources, including no doubt by becoming less dependent on Russian gas supplies. However, the level of shale gas development in those countries is far behind that in other regions of the world. It is also uncertain the extent to which Russia, keen to preserve its regional influence over these countries, might wish to discourage such development.

Russia, on the other hand, has the resources and funds to develop shale gas but is less interested in doing so due to its vast conventional reserves. Although Russia might not affect geopolitics by developing its own shale gas, its economy might be adversely affected by the development of shale gas in the US and other regions.
4. Up-and-coming shale countries

CIS - Shale Gas Resources

On the basis of the map and graph above, recent regulatory developments and our clients’ interests, we have identified Russia and Ukraine as being the most propitious countries for shale gas development in the CIS. The next two chapters explore how these countries deal with some of the key legal contractual to consider for a shale gas project.
Russia

1. Introduction

1.1 Industry background

According to the EIA, Russia is the third-largest producer of liquid fuels and the second-largest producer of dry natural gas. Most of Russia’s production is dominated by domestic firms, with Rosneft, Russia’s NOC, and LUKOIL, a privately-owned company, being Russia’s first and second biggest oil companies, respectively. The state-run Gazprom controls most of Russia’s gas reserves. It is estimated that more than 50% of Russia’s federal budget revenues come from the oil and gas industry.

Gazprom is not rushing to develop Russia’s shale gas due to the country’s extensive conventional reserves, including new pockets being discovered offshore and in the Arctic. Indeed, it is more cost effective for Russia to exploit its conventional resources than to develop its shale gas resources.

1.2 Legal framework

Russia does not have specific regulations for unconventional hydrocarbons. Their exploration, production and protection is governed by the general rules established by the Subsoil Law of 21 February 1992 (“Subsoil Law”) and by the Federal Law on Production Sharing Agreements of 30 December 1995 (“PSA Law”), which are applicable to all hydrocarbons.

1.3 Ownership of hydrocarbon resources

All hydrocarbon reserves while in the soil belong to the Russian state. Once extracted, the reserves generally belong to the licence holders.

1.4 Administration

Administration of Oil and Gas Activities in Russia
As shown in the schematic above, in Russia, the use of natural resources is regulated by the following state agencies and bodies:

- **Federal Government.** The federal government is in charge of the general regulation, grant and termination of certain mineral rights.

- **Ministry of Natural Resources.** The Ministry of Natural Resources is responsible for the regulation and general supervision of the study, use, renewal and conservation of subsoil resources. It also sets policies in these areas.

- **Ministry of Energy.** The Ministry of Energy regulates oil and gas related activities.

- **Federal Agency of Subsoil Use ("Rosnedra").** Rosnedra is in charge of the grant and termination of subsoil licences. However, in some instances (e.g. for all offshore deposits) decisions on licence issuance are taken by the federal government itself.

- **Federal Agency for Environmental Use Supervision ("Rosprirodnadzor").** Rosprirodnadzor supervises licensees' compliance with the applicable laws and the term of their licences.

- **Federal Tax Service.** The Federal Tax Service collects oil and gas related taxes (for example, mineral reserves extraction tax).

- **Federal Service for Environmental, Technical and Nuclear Supervision ("Rostekhnadzor").** Rostekhnadzor supervises, from a technical perspective, operations of all oil and gas related facilities.

- **Federal Tariff Service.** The Federal Tariff Service regulates federal tariffs related to transportation and sales of certain hydrocarbons, as well as access to trunk pipelines.

- **Transneft.** Transneft is the owner of oil trunk pipelines;

- **Gazprom.** Gazprom is the owner of gas trunk pipelines.

## 2. Key contractual issues for a shale gas project

### 2.1 Exploration term

Exploration licences may be granted for a term of up to five years for onshore fields (or seven years in certain specific regions of Russia) or for up to 10 years for offshore deposits. Exploration licences are generally extendable subject to certain conditions. An extension may be granted for any period required for the completion of the work but, in practice, it is usually granted for an additional five year period. There are no restrictions with respect to the number of extensions.

### 2.2 Relinquishments

There are no compulsory relinquishment obligations in Russia.

### 2.3 Exploitation term

Development and production licences may be granted for the term required to complete development of the deposit but, in practice, they are usually granted for a 20 year period. They are generally extendable subject to certain conditions. An extension may be granted for any period required for the completion of the work. There are no restrictions on the number of
extensions. Combined licences (exploration and production) are usually granted for a 25 year period and are also generally extendable subject to certain conditions.

2.4 Delineation exploitation concession

There is no limit on the size of an area covered by a development and production licence.

2.5 NOC participation and carry

There are no legally required maximum or minimum NOC participation interests. However, the exploration and exploitation of oil and gas deposits offshore can only be undertaken by a Russian incorporated legal entity, in the charter capital of which the Russian Federation must have a direct or indirect 50% or greater participation interest.

2.6 Water resources rights

There are no special rules for the use of water resources by holders of subsoil licences with respect to unconventional hydrocarbons. The holders of such licences must obtain special permits for the use of water resources, in accordance with general procedures, from the owners of the water bodies. No special permit is required for underground waters for the exploration or development of unconventional hydrocarbons, provided such water use is envisaged by the approved project documentation.

2.7 Flaring

Flaring is not generally prohibited. However, it:

- is subject to a general threshold limit of flaring no more than 5% of overall extracted gas;
- requires a special permit for emissions of pollutants in the air granted by Rosprirodnadzor; and
- requires that payments are made to compensate for the adverse impact on the environment based on the amounts of emission and the percentage of gas flared. Basic fee rates are established for each pollutant and are influenced by the climate and environmental conditions of a particular region as well as by the danger level of the pollutant. In addition for any flaring in excess of the 5% threshold, basic fee rates will be multiplied by 25.

2.8 Economic stabilisation

Economic stabilisation is envisaged for Production Sharing Agreements ("PSAs") only. In essence, the PSA Law requires the PSA to be amended to protect the investor's legitimately anticipated commercial results if they are compromised by changes in legislation. The rule does not apply if such changes concern standards of safe working practices, protection of subsoil, the environment or public health.

In addition, investors operating under subsoil use licences may qualify as foreign investors and be protected by the Federal Law on Foreign Investments in the Russian Federation No. 160-FZ of 9 July 1999 ("Investment Law"). Under Article 5 of the Investment Law, new regulations which increase the overall tax burden or otherwise adversely affect the regime of foreign investments, will not apply to the foreign investor within the payback period. However, the payback period may not be more than seven years from the date of investment. In addition, Article 5 does not apply to excise duties and VAT for goods manufactured in the Russian Federation. To invoke Article 5, the foreign investor should be implementing an investment
project included by the government of the Russian Federation in the list of “priority investment projects”. Shale gas projects are not currently included in this list.

3. Other contractual issues to consider

3.1 Domestic market obligations

Generally, the law does not establish any general DMO, but they may be provided for in a particular licence or PSA.

<table>
<thead>
<tr>
<th>Issues</th>
<th>Russian Regime</th>
</tr>
</thead>
<tbody>
<tr>
<td>DMO Extent</td>
<td>There is no market practice or standard DMO terms. DMO are quite unusual and always different.</td>
</tr>
<tr>
<td>Shale Gas Exports</td>
<td>As of 1 December 2013 the following companies have the right to export gas:</td>
</tr>
<tr>
<td></td>
<td>• OJSC Gazprom and its subsidiaries; and</td>
</tr>
<tr>
<td></td>
<td>• LNG, with export rights only for:</td>
</tr>
<tr>
<td></td>
<td>o users of strategic deposits (including Russian subsidiaries of foreign companies) whose licences provide for the liquefaction of extracted gas or the construction of an LNG facility; and</td>
</tr>
<tr>
<td></td>
<td>o companies in which the Russian Federation owns more than a 50% participatory interest and their subsidiaries, provided they are producing LNG from gas extracted at offshore fields.</td>
</tr>
<tr>
<td>Sale price of gas sold in the domestic market</td>
<td>• There is no direct regulation of price of oil in the domestic market.</td>
</tr>
<tr>
<td></td>
<td>• Wholesale prices of gas produced by OJSC Gazprom, entities affiliated to Gazprom and owners of regional gas supply systems are set and regulated by the Federal Tariff Service of the Russian Federation. The wholesale price of gas produced by other entities is not regulated.</td>
</tr>
<tr>
<td></td>
<td>• Retail prices of gas for citizens are regulated locally by the governments of subordinate entities of the Russian Federation.</td>
</tr>
<tr>
<td>Repatriation of proceeds and profits</td>
<td>All residents of the Russian Federation while conducting foreign trade activity must ensure transfer of sales proceeds to their accounts opened in Russian banks.</td>
</tr>
</tbody>
</table>

3.2 Fiscal regime and tax incentives

There are no special tax regimes/incentives for shale gas.

3.3 Third party and state access to infrastructure

The Subsoil Law prohibits any form of discrimination of subsoil users with respect to access to transport facilities and infrastructure operated by “natural” monopolies in Russia (mainly oil and gas pipelines, electricity etc.). In the oil and gas sector, there are two key natural monopolies:

• Transneft’s monopoly for transportation and export of crude oil; and

• Gazprom’s monopoly for transportation and export of gas.
Third parties access rights to the infrastructure and facilities operated by the above two natural monopolies are available (subject to certain requirements being met). In addition, as discussed above, the Federal Tariff Service regulates and sets the price for oil and gas transport via these natural monopolies’ infrastructure.

4. Market update

4.1 Recent developments

There are currently no plans to legislate specifically for shale gas in Russia. In October 2013, the Minister of Energy, Alexander Novak, stated that the country will not undertake large scale production of shale gas. There are however a number of companies that have begun exploration in the Bazhenov region of the West Siberian basin, including:

- Lukoil, Rosneft, Gazprom Neft and ExxonMobil in a joint venture with Rosneft; and
- Royal Dutch Shell in a joint venture with Gazprom.

In addition, Rosneft and Statoil have recently signed a joint venture agreement to exploit shale oil in the Domanik shale formation in the Samara region. The joint venture will spend three years on a pilot program assessing the potential for commercial production, planning to drill at least six exploration wells in the region before 2021.

4.2 Key shale basins

The EIA identified the following basins as having technically recoverable shale gas resources in Russia:

Russia Shale Gas Basins

![Map of Russia with highlighted West Siberia basin]

- Technically recoverable resources (trillion cubic feet)
- 285 tcf
4.3 Companies

The following companies are currently involved in shale oil and shale gas operations in Russia:

<table>
<thead>
<tr>
<th>Company</th>
<th>Activity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lukoil</td>
<td>Drilling to assess tight oil deposits in Bazhenov (West Siberian basin).</td>
</tr>
<tr>
<td>Rosneft</td>
<td>Drilling to assess tight oil deposits in Bazhenov.</td>
</tr>
<tr>
<td>Gazprom Neft</td>
<td>Drilling to assess tight oil deposits in Bazhenov.</td>
</tr>
<tr>
<td>ExxonMobil/Rosneft</td>
<td>Joint Venture to assess tight oil deposits in Bazhenov and Achimov.</td>
</tr>
<tr>
<td>Royal Dutch Shell/Gazprom</td>
<td>Joint Venture to assess tight oil deposits in Bazhenov.</td>
</tr>
<tr>
<td>Rosneft/Statoil</td>
<td>Joint Venture to assess shale oil deposits in Samara region (West Siberian basin).</td>
</tr>
</tbody>
</table>

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1. **Introduction**

1.1 **Industry background**

According to the EIA, more than half of Ukraine’s primary energy supply comes from its uranium and coal resources. Ukraine produces approximately 30% of its natural gas consumption and imports the rest from Russia. The small portion of the country’s energy consumption derived from petroleum and other liquid fuels is satisfied primarily by Russian imports as well, with Ukraine producing less than 30% of the petroleum and liquid fuels it consumes.

Ukraine’s recent discoveries of shale gas deposits (128 tcf of technically recoverable shale gas reserves) could decrease the country’s dependence on natural gas imports from Russia. However, such a change could upset the geopolitics in the region since Russia relies on Ukraine as a natural gas transit country. During the 2009 Russia-Ukraine dispute over gas pricing, Russian gas flows through Ukraine were halted, thereby cutting off supplies to south-eastern Europe.

It remains to be seen how the protests against Ukrainian President Viktor Yanukovych’s perceived decision to forego a pact with the European Union, in favour of a closer relationship with Russia, will impact Ukraine’s oil and gas industry. As part of what some are terming a bailout of Ukraine by Russia, Russia temporarily cut the price of natural gas for Ukraine by around a third at the end of 2013.

1.2 **Legal framework**

There is no specific legislation for unconventional oil and gas in Ukraine. Instead, legislation designed for conventional oil and gas development applies, namely:

- Subsoil Code of Ukraine of 1994;
- Oil and Gas Law of 2001;
- Production Sharing Agreements (PSAs) Law of 1999, as amended from time to time ("PSA Law 1999"). In particular, in October 2012, the PSA Law 1999 was amended by the Law No. 5406-VI ("Amendment"), with effect from 7 November 2012. Further to the Amendment, the PSA Law 1999 now contains express references to "unconventional hydrocarbons", which definition includes shale gas. It is recognised that the amended PSA Law 1999 still does not cater for various concerns connected with unconventional hydrocarbon development. However, the PSA Law 1999 enables the parties to depart, to the extent agreed in their PSA, from the legislation applicable to conventional hydrocarbon development; and
- Resolution of the Cabinet of Ministers of Ukraine ("CMU") No. 615 of 2011 ("Resolution 615").

Currently, two PSAs for unconventional hydrocarbons have been awarded in Ukraine:

- a Production Sharing Agreement for the Yuzivska Area signed in January 2013 between (1) the State of Ukraine, (2) Shell Exploration and Production Ukraine Investments (IV) B.V. and (3) Nadra Yuzivska LLC, which covers a tight sand project; and
• a Production Sharing Agreement for Oleska field signed in November 2013 between (1) State of Ukraine, (2) Chevron Ukraine B. V. and (3) LLC "Nadra Oleska", which relates to a shale gas project,

together the “Existing PSAs”.

Given the flexibility built into the legislation, this chapter will, where relevant, reference certain terms of the Existing PSAs to provide an indication as to how the PSAs for unconventional resources may differ from standard PSAs. The Existing PSAs are in the public domain.

1.3 Ownership of hydrocarbon resources

Under Ukrainian law, the state owns all resources contained in the subsoil.

1.4 Administration

**Administration of Shale Gas Activities in the Ukraine**

As shown in the schematic above, in the Ukraine the key regulators in the oil and gas sector are:

• **Ukrainian Parliament** (i.e. the Verkhovna Rada of Ukraine). The Ukrainian Parliament is responsible for creating the legislative framework to the shale gas operation in Ukraine.

• **Ukrainian Government** (i.e. the Cabinet of Ministers of Ukraine). The Ukrainian government is in charge of regulation of activities in the oil and gas sector and:
  o enters into PSAs on behalf of the state; and
  o provides an organisational framework for the conclusion and execution of PSAs through the permanently established interdepartmental commission.

• **State Geology and Subsurface Service of Ukraine** (“SGS”). The SGS's key functions are:
  o granting the necessary licences (special permits) for the exploration and exploitation of shale gas in the Ukraine; and
providing estimates of oil and gas reserves in the Ukraine (through the State Commission of Ukraine on Mineral Reserves).

- **Ministry of Ecology and Natural Resources of Ukraine ("Ministry of Ecology").** The Ministry of Ecology's role consists of:
  - providing the necessary environmental permits for the exploration and exploitation of shale gas in the Ukraine; and
  - registering initial drafts and final versions of the PSAs.

- **The Ministry of Energy and Coal Industry.** The Ministry of Energy and Coal Industry is responsible for developing the legal framework for the diversification of the sources of hydrocarbons extraction and determining the priorities for the development of fuels and energy in Ukraine.

- **Local councils of the territories.** Local councils for the permit area must also approve draft PSAs.

2. **Key contractual issues for a shale gas project**

2.1 **Exploration term**

Pursuant to Resolution 615, exploration, production and construction of underground storage facilities within a gas bearing formation require a "special permit". Special permits for:

- exploration have a maximum term of five years on the mainland;
- geological research with further commercial production have a maximum term of 20 years on the mainland.

Special permits will be extended for the same period as the original term if the applicant complies with the terms and conditions of the special permit and of the agreement on subsoil use. A special permit cannot be extended more than twice, save for where exploration costs are financed by the state budget. Should a special permit be granted to a lessee of an "entire property complex" often specifically constructed or developed for the extraction and processing of relevant minerals extracted under the permit, the term of such permit may be extended in accordance with the terms of the lease contract.

In general, special permits issued in connection with a PSA are issued for the duration of the PSA and can be extended pursuant to the terms agreed and set out in that PSA.

Taking into account the Existing PSAs, it is interesting to note the following provisions, which have been agreed:

- in one case the investor ("investor") (i.e. the operator) is to complete the initial exploration within five years. If no commercial discovery is made after that initial period of five years, the Investor will have the right to request an extension of the initial exploration period, in the following circumstances:
  - to complete the exploration;
  - to fulfil its financial contribution obligations under the permit;

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4 Under Ukrainian law, an "entire property complex" means a set of facilities covering the complete production cycle of a mineral resource.
to explore for minerals previously undiscovered within the same subsurface area; or

- to assess the explored reserves;

- in addition, the initial exploration period will be extended in the event of a delay in exploration caused by circumstances outside the Investor’s control (for example if the state fails to perform its obligations under the PSA). The PSA does not contain a limit on the number of such extensions; and

- the Investor may conduct other exploration activities in any part of the contract area, including the development area. In effect, this Existing PSA allows for continued exploration during exploitation. However, such exploration during development must be approved by an authorised state body. The authorised state body is, in this case, the Ministry of Energy and Coal Industry.

In the other Existing PSA, the Investor must complete the initial exploration program within five years (in this case, 13 wells are to be drilled during exploration stage). This term may be extended upon request of the Investor subject to the approval from the authorised body. The authorised body will be designated by the Ukrainian government.

2.2 Relinquishments

Pursuant to Article 8 of the PSA Law 1999, relinquishments constitute an essential condition of a PSA and a procedure for relinquishment must be set out in each PSA.

In practice, in one case, the Existing PSA provides that at the end of the initial exploration period, the Investor will relinquish any portion of the area located outside of the development area and which offers no potential for further exploration/development.

In another case, the Existing PSA effectively allows the Investor to decide the extent and timing of relinquishment.

2.3 Exploitation term

Pursuant to Resolution 615, exploration, production, and construction of underground storage facilities within a gas bearing formation require a special permit. Special permits for:

- geological research with further commercial production have a maximum term of 20 years on the mainland; and

- industrial development of fields have a maximum term of 20 years on the mainland.

Special permits will be extended for the same term provided the applicant follows the terms and conditions of the special permit and of the agreement on subsoil use. Extensions may only be granted twice. Should a special permit be granted to a lessee of an entire property complex specifically constructed or developed for extraction and processing of relevant minerals extracted under the permit, the term of such permit may be extended in accordance with the terms of the lease contract.

In general, special permits issued in connection with a PSA are issued for the duration of the PSA and can be renewed pursuant to the terms agreed and set out in that PSA.

By way of an example of the implementation of these rules, one of the Existing PSAs has been extended to, unless it is terminated earlier, a term of 50 years (45 years exploitation and five
years exploration period). This Existing PSA contains provisions allowing further extensions, although typically these require the Ukrainian government's approval.

2.4 Delineation exploitation concession

Under Ukrainian legislation, a special permit holder must obtain a certificate, which authorises the special permit holder to use a defined subsurface area. Such certificate is called "a mining allotment act". The mining allotment act is issued following the grant of the special permit and due approval of the extraction project. A special permit holder is not authorised to transfer the rights granted by the mining allotment act (in full or in part) to a third party.

2.5 NOC participation and carry

Under the PSA Law 1999 (as amended) participation of the state in the PSAs is obligatory. The Ukrainian government enters into PSAs on behalf of the state. The Ukrainian government's participation in a PSA takes the form either of a participation by a 100% state-owned entity or by a legal entity which has among its shareholders a 100% state-owned entity.

The PSA determines:

• the percentage interest of the Ukrainian government in the PSA. This number may vary from PSA to PSA; and

• the percentage of hydrocarbons to be allocated to the state and to the Investor respectively. Such profit sharing is subject to the PSA Law 1999, which provides that an Investor cannot receive more than 70% of the production while it is recouping its costs. In practice, once costs have been recovered, the state generally takes between 15-20% of hydrocarbon production.

The Ukrainian government currently owns a 52% participation interest in each of the Existing PSAs. The Ukrainian government participated in these Existing PSAs through the LLC "Nadra Yuzivska" and LLC "Nadra Oleska" respectively, which were incorporated with participation of the state-owned PJSC "NJSC Nadra of Ukraine".

2.6 Water resources rights

Pursuant to Articles 39 and 40 of the Water Code, "special uses of water" require a special permit. Water used in a shale gas development would be considered a special use of water. Special permits can be granted for three to 25 years and be renewed multiple times. Depending on the status of water resources used, special permits are granted by the regional, Kyiv or Sevastopol state administrations, Council of Ministers of the Autonomous Republic of Crimea (for water resources of national significance) or by the regional, Kyiv or Sevastopol councils, or the local environmental state authority of the Autonomous Republic of Crimea. In addition, Article 4 of the PSA Law 1999 provides that the state will ensure the issuance to the Investor and their contractors of approvals, quotas, special permits, other licences and documents certifying use of land and other resources.

In the Existing PSAs, these provisions have effectively been reflected in the undertaking accepted by the state.

2.7 Flaring

Flaring is an issue not dealt with specifically by the PSA Law 1999. However, in the Existing PSAs flaring has been specifically addressed.
2.8 Economic stabilisation

Article 27 of the PSA Law 1999 and the Existing PSAs all provide for economic stabilisation. In essence:

- the state guarantees that amendments and/or supplements to laws and/or regulations, which are made after the PSA becomes effective, shall not apply to the Investor except in the following circumstances:
  - defence;
  - national security;
  - public order; and
  - environmental protection; and

- if a change in law and/or regulations has a significant adverse impact on economic benefits (including those stemming from the fiscal conditions) which any Investor enjoys under the relevant PSA or which are provided to any Investor during the relevant PSA term, the parties shall, as soon as practicable, amend such PSA or perform such other acts that are prudent or necessary in order to restore the overall economic benefit (including the economic benefit from the fiscal conditions) for the Investor.

3. Other contractual issues to consider

3.1 Domestic market obligations

Pursuant to Article 22 of the PSA Law 1999, a PSA may require an Investor to sell part of the hydrocarbons extracted to the state or particular enterprise in Ukraine.

<table>
<thead>
<tr>
<th>Issues</th>
<th>Ukrainian Regime</th>
</tr>
</thead>
<tbody>
<tr>
<td>Shale Gas Exports</td>
<td>• Under Ukrainian law, a licence is required to export natural gas outside of Ukraine. However, this restriction does not apply to natural gas produced under a PSA.</td>
</tr>
<tr>
<td></td>
<td>• Subject to Article 22 of the PSA Law 1999, Investors are free to dispose of part of their production under the PSA at their own discretion. This includes selling gas outside Ukraine at market prices (see Article 34 of the PSA Law 1999).</td>
</tr>
<tr>
<td>Sale price of gas sold in the domestic market</td>
<td>• There is no specific price regulation for shale gas in Ukraine. However, the price of natural gas sold on the domestic market to end consumers is regulated: UAH 3,459 for 1000 m³. Such regulation de facto affects sale prices between traders.</td>
</tr>
<tr>
<td></td>
<td>• Pursuant to the PSA Law 1999, Investors are allowed to sell hydrocarbons at market prices in Ukraine.</td>
</tr>
<tr>
<td>Repatriation of proceeds and profits</td>
<td>Investors under a PSA are exempted from exchange control restrictions and can freely repatriate their investment in Ukraine as well as proceeds and profits arising out of, or in connection with, such investment.</td>
</tr>
</tbody>
</table>

3.2 Fiscal regime and tax incentives

Ukrainian law does not contain any specific tax incentive for shale gas development. However, the Ukrainian Tax Code contains special provisions relating to the taxation of a PSA Investor, in particular an exemption from state and local taxes (save for VAT, CIT and subsurface use
payment) are replaced by the allocation of the production under the PSA between the state and the Investor(s) and:

- exemption from customs clearance fees for import in Ukraine of goods and other property for the purposes of the PSA,
- exemption from VAT and other tax or customs duties when the Investor exports its PSA share of hydrocarbons production outside Ukraine; and
- profits received under the PSA are exempt from the profit repatriation tax.

For example, Article 28 of the PSA Yuzivska and Article 31 of the PSA Oleska specifically set forth exhaustive lists of payable taxes. All other taxes and fees related to PSAs and not specifically identified as payable in these articles, shall not be paid by the relevant Investors regardless of whether the allocation of production under the PSAs has taken place (i.e. even if the PSA has been terminated or deemed invalid).

3.3 Third party and state access to infrastructure


Pursuant to the Pipelines Law, the state owns the existing transport network. The Pipelines Law prohibits the privatisation of Ukrtransgaz (for local pipelines) and Chornomornaftogaz (for main pipelines), the state-owned companies operating the network.

If a private party requests access to the local or the main pipeline network, the operator has to provide access on a non-discriminatory basis. Access can only be refused with grounds. In addition, since 1 January 2013, Ukrtransgaz is under an obligation to grant access and to expand the network to match demand. If capacity is limited, companies supplying households will be given priority.

To date, there are no private pipelines operators in Ukraine. However, the PSA Law 1999 was recently amended to provide PSA Investors with the right to construct and operate pipelines. The Existing PSAs have taken into account this amendment. One Existing PSA provides that each party must make every reasonable effort to make capacity available to each of the other parties to that PSA if the infrastructure it owns exceeds its own needs. Under the other Existing PSA, third parties are allowed to transport their hydrocarbons through any pipeline constructed by the Investor under such conditions approved by the Investor and the state, provided that these conditions shall be non-discriminatory and reasonably commercial. However, Investors are always granted a priority right to use the pipelines they invested in.

4. Market update

4.1 Recent developments

Ukraine's government has signed two deals for shale exploration:

- one with Royal Dutch Shell in January 2013; and
- one with Chevron in November 2013.

Changes were introduced in November 2013 to the legislation regarding the distribution of revenues received by Ukraine under PSAs, which require that 10% of Ukraine's profit be split as follows:
• 5% to the regional budget;
• 3.5% to the district budget; and
• 1.5% to the budget of the local village.

Such changes to the legislation have been taken into account in each of the relevant Existing PSAs.

4.2 Key shale basins

The EIA identified the following basins as having technically recoverable shale gas resources in Ukraine:

Ukraine Shale Gas Basins

Technically Recoverable Resources (trillion cubic feet)

70+ tcf
4.3 Companies

The following companies are currently involved in shale gas operations in Ukraine:

<table>
<thead>
<tr>
<th>Company</th>
<th>Activity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Royal Dutch Shell</td>
<td>Has an exploration licence in the Dnieper Donets basin.</td>
</tr>
<tr>
<td>Chevron</td>
<td>Has an exploration licence in the Carpathian basin.</td>
</tr>
</tbody>
</table>

5. Baker & McKenzie contacts

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Europe

1. Introduction
In Europe, one must distinguish between the approach taken by:

- the European Union ("EU"); and
- each European country (members and non-members of the EU).

1.1 European Union level
Pursuant to Article 194 of the Lisbon Treaty, each Member State has "the right to determine the conditions for exploiting its energy sources, its choice between different energy sources and the general structure of its energy supply". This means that the EU is not allowed to decide the energy mix of Member States and will therefore not be able to:

- impose an EU-wide permitting regime for shale; and/or
- ban shale gas.

However, the EU can introduce new regulations relating to shale gas extraction or tighten existing laws. The key issues currently discussed at the EU level in relation to shale gas are as follows:

- disclosure of chemicals used in fracturing fluids;
- volumes of water required for shale gas activities;
- water contamination;
- spillage or release of chemicals or contaminated water;
- toxicity levels;
- release of emissions into the air;
- degradation or complete removal of a habitat; and
- seismic event risks.

The EU has committed to reduce greenhouse gas emissions to 80% to 95% below 1990 levels by 2050. However, according to the European Commission’s projections, current energy policies will deliver half of that target. In light of this target, the European Commission has acknowledged the key role that shale gas could play in the transition to decarbonisation (see below for more details).

On 21 November 2012, the European Parliament recommended:

- the development of suitable legislative proposals to enable a more harmonised and safe development of unconventional energy projects;
- a thorough analysis of the EU regulatory framework regarding unconventional exploration and exploitation;
- an EU-wide risk management framework for unconventional fossil fuels exploration or extraction (harmonised provisions for protection of human health and the environment);
• the development of a comprehensive European Best Available Techniques Reference for fracking;
• a blanket ban on hydraulic fracturing in certain sensitive and particularly endangered areas (beneath drinking water protection areas and in coal mining areas);
• standardised emergency response plans; and
• that a minimum safety distance should be maintained between drilling pads and water wells.

The European Parliament also noted that mutual non-disclosure agreements regarding damage to environmental, human and animal health are not in line with EU and Member State obligations under the Aarhus Convention, the Access to Information Directive (2003/04/EC) and the Environmental Liability Directive.

On 22 January 2014, the EU Commission released its official recommendation on shale gas. It advocates the implementation of voluntary guidelines on a number of topics, including the monitoring of hydraulic fracturing fluids and well integrity. This recommendation differs from the EU Commission’s earlier stance, which favoured legally binding regulations for shale gas extraction.

1.2 Country level

Currently, as shown in the map below, there are three different attitudes to shale gas in Europe:
• welcome;
• cautious and reserved; and
• banned.

Europe: Shale Gas Reserves and Policy Approaches

- Assessed basins with resource estimate
- Welcome
- Cautious and Reserved
- Banned
2. **Key challenges for a shale gas revolution in Europe**

2.1 **Novelty of unconventional resources**

Europe faces the same novelty issue as Africa in that the development of unconventional resources and the hydraulic fracturing technique it entails are fairly new in Europe, with the notable exception of the UK where:

- shale gas was first accidentally encountered in West Sussex in 1875 (Netherfield) and in Heathfield in 1895, with the gas from the Heathfield well lighting the local railway station until 1934; and
- hydraulic fracturing was first used for onshore conventional operations in the late 1950s and has been a common practice to increase flow rates for both onshore and offshore developments since then.

As shale development is new to the European market, Europeans need to be "educated" on the specificities of shale gas developments, horizontal drilling and hydraulic fracturing. Some IOCs and oil service companies (namely, Chevron, Cuadrilla, Halliburton, Royal Dutch Shell, Statoil and Total Shale Gas Europe) have already started this educational process in Europe, by setting-up a website [http://www.shalegas-europe.eu/en/](http://www.shalegas-europe.eu/en/). This website provides information about shale gas, tight gas and coalbed methane through videos, factsheets and reports that aim to answer some of the most frequently asked questions about these resources.

2.2 **Logistical constraints**

The logistical constraints of shale gas development in Europe include the lack of:

- a skilled workforce and an experienced oilfield services industry;
- access to drilling rigs capable of drilling horizontally;
- strong labour unions and works councils, which can lead to frequent strikes and uncompetitive prices (i.e. higher costs of labour);
- competition with other existing energy sources (renewables, LNG imports, Russian and Algerian pipeline gas and oil);
- a political inclination from European governments, in particular in countries belonging to the EU, to regulate shale gas operations strictly due to concerns for health and safety;
- increased local environmental concern (contamination of drinking water), noise disruption (shale gas drilling is a far noisier and more intensive industrial process than conventional gas drilling); and
- the location of the main shale formations in high population density zones (e.g. Paris basin).

Due to their location, the main shale formations are seen as competing with local populations for access to water. This, combined with state ownership of the subsoil and its minerals (i.e. individuals do not directly benefit from shale gas projects), means that it is harder in Europe to obtain local support for shale gas, with local communities often siding with environmentalists.
3. Looking forward

3.1 A clear need for European shale gas

There are strong arguments for shale gas project developments in Europe. Shale gas is needed for:

3.1.1 Energy sufficiency

In 2010, the EU relied on imports for about 63.5% of its gas consumption. At present contracted gas supply is not enough to meet increasing European demand. New import arrangements are needed for 2015 onwards. The European Commission stated that "[a]t a time when European reserves are being depleted and consumers' appetite continues to increase, natural gas is becoming critically important to the EU", recognising that shale gas could be part of the solution to meet European consumers' ever increasing demand for energy.

3.1.2 Energy security

Since the 2008 transit dispute between Russia and Ukraine, which suspended delivery of gas supplies to Europe, highlighting Europe's dependence on Russia for energy, the EU has focused on diversifying gas sources, routes and suppliers. This focus has been echoed in the Former Soviet Union ("FSU") states which, since the fall of the USSR in December 1991, have sought to establish and maintain independence from Russia while retaining a healthy relationship.

Shale gas is increasingly being seen as part of the solution to decrease dependence on Russia, whilst increasing security of gas supply.

3.1.3 Price stability

An increasing reliance on imports for energy means a greater exposure to the risk of fluctuating prices caused by supply disruptions, market shocks or political brinkmanship. Shale gas project development in Europe would decrease reliance on imports for energy, lowering exposure to fluctuating gas prices and providing a certain price stability. It would also contribute to market competition and hence give gas importing countries more leverage to renegotiate existing gas import contracts. Finally, in the US the shale gas revolution has both delinked the price of natural gas from the price of oil and lowered the price of natural gas for end consumers. The same impacts are likely to occur in Europe if a European shale gas revolution were to become a reality.

3.1.4 Boosting the economy

The US experience demonstrates that the shale gas industry is a significant source of tax revenue for governments. The same would be true in Europe. For example, in the UK, Cuadrilla estimates that the UK government would be due between £5 and 6 billion in tax alone during the 30 year lifespan of its project. In addition, shale gas projects will increase tax revenues through income tax paid by employees of IOCs developing such projects.

Having natural gas (ethylene) as a cheap feedstock has also boosted the US chemical industry, giving it a competitive advantage over the EU chemical industry (which uses naphtha, the price of which is linked to oil prices) and kick-starting an on-shoring trend, thereby bringing back production capacity to the US. At the moment, the EU chemical industry needs to catch up or it will lose market share. European shale gas development could enable the EU chemical industry to regain its competitiveness, whilst opening the door to EU on-shoring.
The employer multiplier effect of shale gas projects must also be considered. Shale gas projects appear to have an employer multiplier effect of three. This means that for every direct job created by a shale gas project, three indirect jobs are created. In the US, about 600,000 people are employed in the shale gas industry. This is expected to rise to 1.6 million by 2035. In the UK, Cuadrilla projects that its production operations in the Bowland Shale, Lancashire, would create 5,600 jobs.

3.1.5 Decarbonisation

The US provides evidence that the use of shale gas lowers CO₂ emissions. Indeed, a report by the IEA shows that due to a major shift from coal to gas-fired power plants, the shale gas boom in the US has enabled a reduction in energy-related CO₂ emissions by 450 million tonnes over the past five years.

In addition, a recent study by the European Commission finds that when emissions are considered for the entire lifecycle of each fuel, modern gas-fired power plants have a carbon footprint that is 41% to 49% lower than that of coal-fired plants.

This means that shale gas could be used as a transition fuel to help the EU meet its 2050 CO₂ emission reduction targets.

3.2 A variable and uncertain future for European shale gas production

3.2.1 Country specific

Not every country in Europe will benefit from a shale gas revolution. A true shale gas revolution, similar to the one in the US, can only occur in countries that have sufficient technically recoverable and economically exploitable shale gas resources.

3.2.2 Linked to production costs

The future of shale gas in Europe will depend on its production costs, and thus it remains uncertain. Currently, European shale gas is expected to be at least twice as expensive to extract as in the US due to deeper geological layers, tougher regulations and a less competitive and more oligopolistic oil and gas service sector.

So far, only a handful of test wells have been sunk in Europe and there have been some unsuccessful results:

- Porto Energy Corp. announced disappointing results from the drilling of the Alcobaça-1 Presalt exploration well onshore Portugal and decided to abandon shale gas exploration; and
- Exxon Mobil pulled out of its exploration for shale in Poland after tests failed to find gas in commercial quantities in the Lublin and Podlasie basins. This move was followed by Talisman Energy, Marathon and Eni.

However, in July 2013, Lane Energy Poland, an exploration company controlled by ConocoPhillips, reported that it was extracting approximately 8,000 m³ of shale gas per day at a test well in Lebork, Poland. Whilst this is still short of the levels required for commercial production, it represents a significant breakthrough for shale gas extraction in Poland.

More seismic testing and well sinks are required to forecast whether Europe's shale plays will be as productive as those in the US. Overall, it may take 12-14 years before European shale gas can be added to Europe's energy supplies: five years to assess whether shale gas exists in
commercial quantities, another five years before production starts and then a few more years before enough shale gas is produced to significantly add to European supplies.

4. **Up-and-coming shale countries**

**Europe - Shale Gas Resources**

On the basis of the map and graph above (respectively showing the amount of shale gas resources in Europe and IOCs/NOCs’ activity in that region), recent regulatory developments, and our clients’ interests, we have identified Poland and the UK as the countries with the most...
prospects for shale gas development in Europe. The next two chapters will explore how these countries’ legislation addresses some of the key contractual issues to consider for a shale gas project.
Poland

1. **Introduction**

1.1 **Industry background**

Poland is a net oil and natural gas importer. It has a limited, mostly state-owned oil industry that produces oil onshore from small fields and offshore in the Baltic Sea. Although it produces a small quantity of natural gas, Poland satisfies its remaining gas demand by importing gas, around two thirds of which comes from the former Soviet Union countries via legacy pipelines. As the second largest coal producer in Europe, Poland’s electricity sector is dominated by coal-fired power plants.

Poland is eager to develop its shale resources to replace expensive gas imports from Russia and other countries. Moreover, Poland looks to develop its shale resources in order to retire or convert its fleet of coal-fired generation plants.

Both Poland’s infrastructure and public opinion largely support the country’s development of its shale resources. However, its shale industry is still at an exploratory, pre-commercial phase with shale gas operations slowing down following the discontinuance of some IOCs’ shale explorations in Poland. Possible investors in Poland’s shale resources are carefully watching the government’s draft law on shale gas exploration, extraction and taxation (“Draft Regulations”).

1.2 **Legal framework**

The Act on Mining and Geological Law of 9 June 2011 (Journal of Laws of 2011, No. 163, item 981, as amended) (“Act on Mining and Geological Law”) is the main instrument currently governing the process of shale gas exploration and exploitation.

As stated above, the Polish government’s first draft of the Draft Regulations was prepared in March 2013, and the Draft Regulations are expected to come into force on 1 January 2015. The current regime will be amended as follows (subject to any changes made prior to enactment):

- **The type of licence.** The current regime of two separate licences will be replaced by a unitary prospecting and production licence. Companies with existing exploration licences will have to enter into a competitive tender to transfer these into the unitary prospecting and production licence;

- **The establishment of a National Operator of Energy Resources** (in Polish *Narodowy Operator Kopalin Energetycznych* (“NOKE”). NOKE will have a participation right in all new hydrocarbon licences through a mandatory co-operation agreement with the licensee; and

- **A new hydrocarbon tax regime.**

1.3 **Ownership of hydrocarbon resources**

The State Treasury owns all hydrocarbon resources. Licensees from the Ministry of Environment are required to begin shale gas exploitation and exploration and obtain a mining usufruct, which is secured via agreement concluded with the Ministry of Environment.
1.4 Administration

Administration of Shale Gas Activities in Poland

As shown in the schematic above, in Poland, the key regulators in the oil and gas sector are:

- **Ministry of Environment (in Polish, Ministerstwo Środowiska).** The Ministry of Environment is the state ministry responsible for oil, gas and mining in Poland. Its role consists of:
  - preparing and implementing laws, regulations and policies for the energy and mining sector (the Polish government is responsible for the initial creation of primary legislation and energy policy);
  - granting licences for the exploration and exploitation of shale gas blocks;
  - concluding mining usufruct agreements giving the right to explore or exploit underground natural resources to the exclusion of any other third parties; and
  - managing and updating the databases on the exploration and exploitation of hydrocarbons, as well as the progress of any licence applications.

- **State Treasury.** The State Treasury has ownership, on behalf of the Polish state, of all hydrocarbon deposits in Poland. Under current legislation, once a mining usufruct agreement is concluded between the Ministry of the Environment and the relevant IOC, the State Treasury has no ownership in the exploration/exploitation concession or in the hydrocarbons produced under such exploration/exploitation concession. It does, however, receive fees, remuneration and royalties from the mining usufructuaries.

As noted above, the Draft Regulations also envisage the creation of NOKE.
2. **Key contractual issues for a shale gas project**

2.1 **Exploration term**

To conduct oil and gas exploration in Poland, both an exploration concession and a mining usufruct agreement are needed. The exploration concession is granted by the Ministry of Environment and gives the concession holder the right to conduct the relevant works. The mining usufruct agreement is concluded between the Ministry of Environment and the concession holder and gives the concession holder the right to use the deposit. For shale gas activities, both the exploration concession and the mining usufruct agreement can be awarded for a maximum term of 50 years. However, in practice, both are granted for a period of ten years.

2.2 **Relinquishments**

Specific terms and conditions of relinquishments (if any) are generally set out in the mining usufruct agreement.

2.3 **Exploitation term**

Unconventional oil and gas exploitation activities, like conventional oil and gas exploration activities, require both an exploitation concession and a mining usufruct agreement. Again, for shale gas activities, both the exploitation concession and mining usufruct agreement can be obtained for a maximum term of 50 years. As shale gas exploitation activities in Poland have not begun yet, there is no practice as regards the term for which the shale gas exploitation concessions and mining usufruct agreements will be issued.

There is in Poland a priority right, that an entity, which has identified a mineral deposit, has, after:

- appropriately evidencing the deposit; and
- obtaining the decision approving the geological documentation of such deposit,

and within five years from obtaining such decision approving the geological documentation, such entity has priority over other entities to conclude a mining usufruct agreement over such deposit.

2.4 **Delineation exploitation concession**

In Poland, the area of the shale gas exploration concession may not exceed 1,200 km². There is no limit on the exploitation concession area, though it will be no larger than the exploration concession area of 1,200 km².

2.5 **NOC participation and carry**

Currently, there is no legally required NOC participation in exploration and/or exploitation concessions. However, the Draft Regulations, in their current form, provide that NOKE will participate in prospecting and production activities. This will be through a mandatory co-operation agreement with the licensee. NOKE's share of the costs incurred under the co-operation agreement will be capped at 5% and will be excluded from contributions to civil liability insurance. NOKE's share of the profits in the unitary prospecting-production licence will be determined in the competitive tender for the licence.

2.6 **Water resources rights**

The use of water is addressed by Polish law on a general basis without particular reference to shale gas activities. A water permit may be issued if the planned activity will not contravene the
local water plans or the requirements in respect of human health, the environment and cultural goods.

Generally, a water permit is issued by the starost (i.e. the head of the local administrative division). However, depending on the purpose of issuing such a permit, it may be also granted by other authorities as, for example, the voivodeship marshal. The term of such permit depends on the type of water permit issued. Thus, in practice a water permit can be issued for a term shorter than the life of the mining usufruct/concession.

Under Polish law, a water permit for surface or underground water intake is not required if:

- the water intake does not exceed five cubic metres per day; or
- the intake is for the purpose of drilling or performing explosive boreholes with the use of water to drill mud for seismic tests.

2.7 Flaring

The Act on Mining and Geological Law, the Ministerial Ordinance on Environmental Impact Assessment 2008 and the Law on Environmental Protection 2001 address flaring in the context of shale gas activities. In essence, gas that will not be marketed and exceeds operational requirements can be flared without obtaining consent from the Ministry of Environment.

2.8 Economic stabilisation

There are no economic stabilisation arrangements under Polish law.

3. Other contractual issues to consider

3.1 Domestic market obligations

Currently (as shale gas exploitation has not started yet), there are no specific domestic market obligations regarding shale gas or conventional hydrocarbons.

<table>
<thead>
<tr>
<th>Issues</th>
<th>Polish Regime</th>
</tr>
</thead>
<tbody>
<tr>
<td>Shale Gas Exports</td>
<td>There are currently no legal restrictions on gas exports. However, there are technical limitations relating to lack of relevant infrastructure which impede gas exports.</td>
</tr>
</tbody>
</table>
| Sale price of gas sold in the domestic market | • To date, there are no specific rules for determining shale gas prices for the domestic market.  
• For conventional oil there is no price setting regime. In general, for sales of gas to small offtakers (buying less than 25 million cubic metres of gas per year) tariffs must be approved by the President of the Energy Regulatory Office. However, the Polish government is in the process of liberalising the market with the aim to release the prices for all offtakers (except for households).  
• Intervention with open market price determination will only be made when the fuel security of the state is in danger. |
3.2 Fiscal regime and tax incentives

As part of the Draft Regulations, the Polish government is working on new specific taxes on hydrocarbons (a special tax on hydrocarbons and a tax on exploitation of fossil fuels). The Polish government is also planning to increase exploitation fees. However, these changes would only be introduced from 2015 to 2020 and have not yet been approved by the Parliament. Therefore, the final shape of those regulations is not known at the moment.

3.3 Third party and state access to infrastructure

The Energy Law Act 1997 (as amended from time to time) stipulates provisions which guarantee third party access to gas networks. This is based on the third party access rule which requires that a third party must be given access to transportation infrastructure when the third party:

- meets the technical and economic requirements for connection to the system;
- concludes an agreement with the infrastructure owner; and
- pays an interconnection fee. The fee is set in the tariff of the relevant company. Such tariff has to be approved by the President of the Energy Regulatory Office.

4. Market update

4.1 Recent developments

A new bill to amend the Act on Mining and Geological Law has been proposed ("Bill"). This Bill amends the environmental impact assessment laws for shale gas. The Bill reduces the scope of the environmental impact assessment tests required for shale gas projects and upfront costs. The Bill also delays the requirement to obtain a decision on environmental conditions until a later stage in projects. As fracking is already taking place in Poland, the new Bill contains transitional provisions to deal with issues arising in relation to licences already granted.

As of June 2013, there are 111 concessions for shale gas and two for tight gas, covering 88,000 km², with 43 exploration wells, of which nine carry out hydraulic fracturing and four have horizontal sections. However, in June 2012 Exxon Mobil pulled out of its exploration after tests failed to find gas in commercial quantities in the Lublin and Podlasie basins, followed by Talisman Energy and Marathon, and in January 2014 Eni also pulled out of its exploration. However, Chevron is still actively exploring for shale gas in Poland and San Leon Energy Plc recently announced that testing at one of its vertical wells, located near the northern city of Gdansk, has been a success. Natural gas flowed from this vertical well at as much as 60,000 cubic feet per day during tests. San Leon is planning to drill a horizontal lateral to that well by July 2014.
4.2 Key shale basins

The EIA identified the following basins as having technically recoverable shale gas resources in Poland:

4.3 Companies

The following companies are currently involved in shale gas operations in Poland:

<table>
<thead>
<tr>
<th>Company</th>
<th>Activity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Exxon Mobil, Talisman and Marathon (in partnership with Nexen)</td>
<td>Tests failed to find gas in commercial quantities and Exxon Mobil, Talisman and Marathon have pulled out of exploration.</td>
</tr>
<tr>
<td>Eni</td>
<td>Eni pulled out of exploration in January 2014 and is allowing its three licences to expire.</td>
</tr>
<tr>
<td>BNK Petroleum</td>
<td>Holds six concessions for shale gas exploration.</td>
</tr>
<tr>
<td>Chevron</td>
<td>Four exploration concessions. Chevron has also signed a Memorandum of Understanding with the Polish state-controlled energy company PGNiG. This memorandum provides for Chevron and PGNiG initial collaboration in exploring potential shale gas projects. If exploration is successful it is then envisaged that a joint venture would be established to operate four licences in south-eastern Poland, two that are currently</td>
</tr>
<tr>
<td>Company</td>
<td>Activity</td>
</tr>
<tr>
<td>-------------------------</td>
<td>---------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Halliburton</td>
<td>With San Leon Energy Plc, plans to explore shale gas.</td>
</tr>
<tr>
<td>San Leon Energy Plc</td>
<td>With Halliburton, plans to explore shale gas.</td>
</tr>
<tr>
<td>Weatherford International</td>
<td>Active in oil services.</td>
</tr>
<tr>
<td>GX Technology</td>
<td>Signed a Memorandum of Understanding with three Polish Institutes for research co-operation.</td>
</tr>
<tr>
<td>ION</td>
<td>Regional seismic program.</td>
</tr>
<tr>
<td>ConocoPhillips</td>
<td>Holds a 70% interest in three western Baltic Basic concessions through Lane Energy Poland.</td>
</tr>
<tr>
<td>Cuadrilla</td>
<td>Holds an exploration licence in Lublin.</td>
</tr>
</tbody>
</table>

5. **Baker & McKenzie contacts**

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UK

1. Introduction

1.1 Industry background

The UK’s offshore fields (primarily in the North Sea) have the largest oil and gas reserves in Western Europe. First exploited in the 1960s, the UK is the largest producer of oil and the second largest producer of natural gas in the EU. Following years of aggressive production, in 2004 and 2005 the UK became a net importer of natural gas and crude oil respectively. It is however estimated that the UK’s continental shelf has the potential to satisfy close to 50% of the UK’s oil and gas demand in 2020 if current levels of investment are maintained. Indeed, according to the EIA Report, in the UK, technically recoverable shale gas reserves are estimated to be 26 tcf and technically recoverable shale oil around 0.7 billion barrels.

However, the UK industry is facing some problems, including decommissioning of fields (which has slowed production), increased levels of health and safety regulations and a rise in the taxation of profits from oil and gas since 2011. In a move to increase investment the UK government has recently introduced a new streamlined third party access regime and a system of "shale gas paid allowances" to provide tax incentives for certain categories of oil and gas field.

1.2 Legal framework

Various pieces of legislation in the UK cover the activities associated with unconventional gas developments but do not address their use specifically for such a purpose. The relevant legislation includes:

- the Petroleum Act 1998 ("PA 1998"), which provide that companies can obtain Petroleum Exploration and Development Licences ("PEDLs") to search and bore for and get petroleum or natural gas. Each PEDLs has a set format and includes standard conditions called "Model Clauses";
- the Hydrocarbons Licensing Directive Regulations 1995;
- the Environmental Planning Regulations 2010;
- the Town and Country Planning Act 1990;
- the Town and Country Planning (Environmental Impact Assessment) Regulations 2011;
- the Planning and Compensation Act 1991;
- the Environment Act 1995;
- the Energy Act 1976;
- the Petroleum (Production) (Landward Areas) Regulations 1995;
- the Water Resources Act 1991;
- the Mining Industry Act 1926;
- the Coal Industry Act 1994;
- the Science and Technology Act 1965;
- the Health and Safety at Work etc. Act 1974;
• the Borehole Sites and Operations Regulations 1995 (particularly Reg. 6); and

• the Offshore Installations and Wells (Design and Construction, etc.) Regulations 1996, which applies to all wells drilled with a view to the extraction of petroleum regardless of whether they are onshore or offshore.

The terms and durations of current licences have provided the right framework for the early exploration activities for shale gas, but may need further development to match the needs of a production phase. On 17 December 2013, the Department of Energy & Climate Change ("DECC"), published a roadmap to the permitting and permissions process for onshore exploratory work in oil and gas development. The focus of this roadmap is on the exploration and appraisal phases of unconventional oil and gas operations (in particular shale gas and coalbed methane developments).

1.3 Ownership of hydrocarbon resources

Pursuant to the PA 1998, all mineral rights in relation to land are vested in the Crown and the Secretary of State of Energy and Climate Change ("Secretary of State") has the power to grant licences to explore, develop and produce oil and natural gas reserves. The Secretary of State usually awards licences through competitive licensing rounds. The Secretary of State and DECC are responsible for regulating and developing the oil and gas industry in the UK. However, licensees must also obtain consent from the landowner for vertical drilling and the consent from any landowners under whose land there will be horizontal drilling (Bocardo SA v Star Energy [2010] UKSC 35).

As discussed previously, when the subsoil is owned by the state the landowner's consent can be difficult to obtain as the landowner has no rights to the resources that the licensee produces, and therefore lacks a financial incentive (e.g. payment of a royalty) for granting the licence. UK law partially addresses this issue by providing that the licensee must pay the landowner compensation for the right to access its land. Such compensation will be privately negotiated between the licensee and the landowner. However, if the landowner and the licensee fail to agree the licensee can seek to enforce a right of access under the PA 1998. Such possibility of enforcement undermines the landowner's bargaining power and renders compensation not as lucrative a financial incentive than a royalty arrangement would be.

To increase local support for the exploitation of shale gas, the United Kingdom Onshore Operations Group ("UKOOG") has developed an engagement charter. The charter encourages oil and gas companies to give £100,000 per well site to the local community and to donate 1% of all production revenues to the local area.
1.4 Administration

Administration of Oil & Gas Onshore Exploration and Appraisal Activities in England

As shown in the schematic above, in the UK, the key regulators in the oil and gas sector are:

- **Coal Authority.** The Coal Authority is a non-departmental public body sponsored by DECC. The Coal Authority owns the majority of unworked coal in Great Britain and former coal mines. It regulates access to coal by licensing coal mining operations, dealing with matters in respect of coal mining subsidence outside the areas of responsibility of coal mining licensees, handling property and historic liability issues and providing access to coal mining information to the public. In the context of unconventional hydrocarbon operations, a permit from the Coal Authority will be required if any planned well encroaches on coal seams.

- **DECC.** Part of the role of DECC’s mandate is to ensure energy security and to try to maximise the value of the UK’s indigenous oil and gas reserves. The DECC’s Energy Development Unit is responsible for managing the UK’s onshore and offshore hydrocarbon reserves. For unconventional hydrocarbon operations, the Energy Development Unit:
  - issues PEDL, the only type of licence available for onshore projects; and
  - reviews the environmental risk assessment ("ERA") carried out by the operator. The ERA is an overview assessment of all environmental risks, including risks to human health, during the entire life cycle of the proposed operations (including decommissioning operations). It should be carried out before application to the MPAs for planning permission and should involve all stakeholders including local communities.

- **Environmental Agency.** The Environmental Agency is an executive non-departmental public body. The Environmental Agency is the environmental regulator for unconventional hydrocarbon operations in England. It ensures that unconventional hydrocarbon operations do not harm people and/or the environment and is responsible for issuing environmental permits.
• **Health and Safety Executive ("HSE").** HSE is a non-departmental public body. It is responsible for the regulation of health, safety and welfare in the workplace. In the context of unconventional hydrocarbons, HSE monitors well integrity and site safety practices. It ensures that design and construction of well casings are appropriate to mitigate environmental risks and that safe working practices are adopted on the site.

• **Minerals Planning Authorities ("MPAs").** MPAs are local authorities responsible for mineral planning. The MPAs are empowered to formulate planning policies and to grant any planning permissions required for a project. Prior to applying for a planning permission, operators are encouraged to consult with the MPA on issues such as noise, ecology, archaeology, site access and visual impact. The MPA will determine whether a shale gas project will require an environmental impact assessment ("UK EIA") and the scope of such UK EIA. UK EIAs are obligatory where over 500,000 m$^3$/d will be extracted. The UK EIA will consist of a systematic assessment of the likely significant environmental effects of the shale gas project. Once the UK EIA is completed, its results will be presented in an environmental statement ("ES"). The ES should include:
  
  o "a description of the development comprising information on the site and the design and size of the development;"
  
  o "a description of the measures envisaged to avoid, reduce and, if possible, remedy significant adverse effects;"
  
  o "the data required to identify and assess the main effects that the development is likely to have on the environment;"
  
  o "an outline of the main alternatives studied by the applicant or appellant, and an indication of the main reasons for the choice made, taking into account the environmental effects; and"
  
  o "a non-technical summary of the information provided pursuant to the paragraph above".

• **Office of Unconventional Gas and Oil ("OUGO").** The OUGO is a new UK government office, established in March 2013. The OUGO has been established to act as a single point of contact for investors in unconventional hydrocarbons, review the regulations currently applying to unconventional hydrocarbons and ensure that any overlaps are rationalised. It will also promote the safe, responsible and environmentally sound recovery of the UK's unconventional hydrocarbons.

• **UKOOG.** UKOOG is the representative body for UK onshore oil and gas companies.

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2. Key contractual issues for a shale gas project

2.1 Exploration term

Most PEDLs follow a standard format of three phases: exploration, appraisal and production. However, DECC has advised that it is flexible and could adapt "new licences to suit special scenarios."

For standard PEDLs, by combining the exploration and appraisal phases, the exploration term can, in effect, be a maximum of 11 years, consisting of:

• a six year "Initial Term" for exploration; and
• a five year "Second Term" for appraisal.

A PEDL expires automatically at the end of each term, unless the licensee has sufficiently progressed (i.e. completed the work program related to such term) to warrant a chance to move into the next term.

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6Source: Department of Energy & Climate Change, Oil and gas: petroleum licensing guidance, which can be accessed at: https://www.gov.uk/oil-and-gas-petroleum-licensing-guidance
2.2 Relinquishments

Under a PEDL the licensee must surrender 50% of the originally licensed area at the end of the Initial Term.

2.3 Exploitation term

The third phase of a PEDL is the production phase, which is granted for 20 years. The Secretary of State can extend the term if production is continuing. DECC also recognises that it is not desirable for production to cease simply because the term of the licence has expired, and therefore has a policy of extending licences where the relevant criteria are met.

2.4 Delineation exploitation concession

There is no limit to the size of an exploitation concession in the UK. A PEDL licensed area is established using a system of blocks identified by the joining of lines with designated coordinates. These blocks are set out in a schedule to the PEDL.

2.5 NOC participation and carry

There is no compulsory state participation in licences under UK law. The UK does not have a NOC and oil and gas development is carried out through IOCs.

2.6 Water resources rights

An environmental permit from the Environmental Agency will be required for the following:

- any groundwater activity (except where any contrary opinion is provided by the Environmental Agency);
- water discharge activity;
- to extract more than 20 m$^3$/d of water; and
- if the proposed site is near a watercourse or main river.

2.7 Flaring

Pursuant to Section 23 of the PA 1998, consent will need to be obtained from DECC before flaring any gas. In addition, where a field will be flaring:

- less than 10 tonnes per day, no permit nor consent will be required;
- more than 10 tonnes per day, but less than 50 tonnes per day, an environmental permit from the Environment Agency and an annual flare consent will need to be obtained; and
- 50 tonnes or more per day, an environmental permit from the Environment Agency and a longer term flare consent can be applied for with a less rigorous application process.

2.8 Economic stabilisation

Neither the PA 1998 nor the Model Clauses included in the PEDLs provide for economic stabilisation measures.
3. Other contractual issues to consider

3.1 Domestic market obligations

Pursuant to Sections 1 and 2 of the Energy Act 1976, in an energy security emergency, the Secretary of State can intervene into the oil and gas market and make reservations for local use.

<table>
<thead>
<tr>
<th>Issues</th>
<th>UK Regime</th>
</tr>
</thead>
<tbody>
<tr>
<td>Shale Gas Exports</td>
<td>Subject to Sections 1 and 2 of the Energy Act 1976 (discussed above), there are no restrictions on gas exports.</td>
</tr>
<tr>
<td>Sale price of gas sold in the domestic market</td>
<td>Gas is not subject to a mandatory price setting regime.</td>
</tr>
<tr>
<td>Repatriation of proceeds and profits</td>
<td>There is no limitation on profits repatriation in the UK. However, to be a licensee a company must have a place of business within the UK and the DECC has the power to make a public interest assessment of the impact of a foreign company on the market.</td>
</tr>
</tbody>
</table>

3.2 Fiscal regime and tax incentives

The UK government is currently consulting on new fiscal incentives for onshore shale gas exploration and production in the UK which will be enacted in 2014. The reforms will reduce the head-line rate of UK tax on a proportion of shale gas profits from certain onshore sites in the UK to as low as 30%, from the current level of 62% on UK oil and gas profits generally. The government's policy is to support the early development of onshore oil and gas projects in the UK, which are economic but not commercially viable at the 62% tax rate. The government's proposals are intended to drive early investment in UK shale gas exploration and development by supporting the sector in its early stages when the government recognises that costs are likely to be higher and the risks of unsuccessful exploration are greater.

Onshore shale gas production profits fall within the UK’s existing "ring-fence" corporation tax regime and are subject to UK corporation tax at the rate of 30%. Certain restrictions "ring-fence" such profits from losses arising from other activities and restrict the deductibility of finance costs incurred on other non-ring fenced activities. Shale gas profits are subject to the UK corporation tax supplementary charge at the rate of 32%, based on the adjusted ring-fenced corporation tax profits, but excluding finance costs generally. This results in an effective head-line UK tax rate of 62%.

The UK government proposals focus on the introduction of a new "onshore allowance" which will apply to onshore shale gas drilling and extraction sites, and which will apply to both conventional and unconventional hydrocarbons:

- the allowance will exempt a portion of oil and gas profits from the supplementary charge by reference to broadly 75% of capital expenditure on the exploration, appraisal, development and production of onshore oil and gas, including the acquisition of onshore oil and gas rights; and

- the allowance will not apply where production from the site is either expected to exceed seven million tonnes, or where production from the site actually exceeds that threshold.

The government also proposes to extend the ring fence expenditure supplement for shale gas projects from six to ten accounting periods. This will enhance the value of certain unused UK tax
allowances and losses, recognising the longer payback period for shale gas projects. This will extend to all onshore unconventional hydrocarbon projects in the UK\(^7\).

3.3 Third party and state access to infrastructure

The Energy Act 2011 governs access to onshore pipelines. Third parties must negotiate with the owner of the pipeline network to agree commercial terms and a tariff. If an agreement cannot be reached then the dispute must be referred to the Secretary of State. If the Secretary of State is satisfied that granting access will not prejudice the efficient operation of the pipeline or existing contractual arrangements then the pipeline owner can be required to enter into an agreement on the basis of terms and a tariff set by the Secretary of State.

4. Market update

4.1 Recent developments

The moratorium on fracking imposed in May 2011, following seismic activity at the Cuadrilla site in Lancashire, was lifted on 13 December 2012. However, Cuadrilla has suspended all drilling at St Anne’s, Lancashire, until 2014 citing environmental concerns. Cuadrilla also removed its rigs from Balcombe, West Sussex in September 2013 following protests but plans to continue exploration there.

In June 2013, Centrica acquired a 25% interest in the Bowland exploration licence from Cuadrilla. Coastal Oil and Gas Ltd, Dart Energy and Eden Energy are also evaluating shale gas potential but have not yet drilled any wells. Celtique Energie holds licences for the Cheshire Basin, East Midlands and the Weald Basin and IGas is planning on applying for a licence to drill for shale gas in Lancashire and Cheshire.

In December 2013 DECC published its regulatory roadmap\(^8\) for shale gas which sets out the series of permits and permissions developers need to obtain prior to drilling. Further to the benefits to the local community stemming from UKOOG’s engagement charter, in January 2014 the government promised that local councils could keep 100% of the business rates they collect from IOCs engaged in shale gas exploration. Although commercial extraction has not yet started in the UK, to date DECC has awarded a total of 334 landward licences for onshore petroleum and gas exploration (97 PEDLs were awarded in the 13\(^{th}\) onshore licensing round in 2008), a number of which were granted over prospective shale plays. The 14\(^{th}\) onshore licensing round for PEDLs is expected to take place in early 2014. On 13 January 2014, Total became the first major oil and gas company to invest in the UK when it acquired an interest in two exploration licences in Lincolnshire.

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4.2 Key shale basins

The EIA identified the following basins as having technically recoverable shale gas resources in the UK:

Great Britain Shale Gas Basins

Technically Recoverable Resources (trillion cubic feet)

- <1 tcf
- 1-30 tcf

Note: The figures represent the technically recoverable resources in total for the North UK Carboniferous and South UK Jurassic Basins.
4.3 Companies

The following companies are currently involved in shale gas operations in the UK:

<table>
<thead>
<tr>
<th>Company</th>
<th>Activity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cuadrilla</td>
<td>Has a licence, but has pulled out of all drilling at the St Anne's site in Lancashire citing environmental concerns.</td>
</tr>
<tr>
<td>Coastal Oil and Gas Ltd</td>
<td>Evaluating shale gas potential, not yet drilled any wells.</td>
</tr>
<tr>
<td>Dart Energy/GDF Suez</td>
<td>Evaluating shale gas potential, not yet drilled any wells.</td>
</tr>
<tr>
<td>Eden Energy</td>
<td>Evaluating shale gas potential, not yet drilled any wells.</td>
</tr>
<tr>
<td>Celtique Energie</td>
<td>Holds licences for the Cheshire Basin, East Midlands and the Weald Basin.</td>
</tr>
<tr>
<td>Centrica</td>
<td>Holds a 25% interest in Bowland exploration licence. Cuadrilla owns the remaining 75%.</td>
</tr>
<tr>
<td>Total S.A.</td>
<td>Holds a 40% interest in two exploration licences in Lincolnshire. In these licences, Total S.A is in partnership with GP Energy (a subsidiary of Dart Energy) (17.5%), Egdon Resources UK (14.5%), IGas Energy (14.5%) and ECorp International (13.5%).</td>
</tr>
<tr>
<td>IGas</td>
<td>Holds licences for the Cheshire basin.</td>
</tr>
</tbody>
</table>

5. Baker & McKenzie contacts

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1. Introduction

In Latin America, attitudes towards shale exploration and production vary by country. As detailed in the map below, around half of the Latin American countries with shale gas resources welcome shale gas development, with the other half taking a more cautious and reserved approach. Argentina has the largest technically recoverable shale gas reserves in the region, with Brazil and Venezuela placing second and third, respectively.

This Guide addresses Mexico in the subsequent chapter about North America.

2. Key challenges for a shale gas revolution in Latin America

2.1 Nationalisation trend

Latin America’s various waves of nationalisations throughout the 20th and continuing into the 21st centuries are barriers to the country achieving its shale gas revolution because they discourage investment. In 2012, Argentina compulsorily acquired Repsol’s majority stake in YPF S.A. (“YPF”), Argentina’s NOC. Argentina has also nationalised its pension funds and Aerolineas Argentinas, an airline. In addition, the ongoing controversy between Argentina and Britain over the Falkland Islands has hindered oil exploration in the region.
Although Venezuela’s NOC Petróleos de Venezuela S.A. was nationalised in 1976, the Bolivarian Revolution led by Hugo Chávez and continued by Nicolas Márduro saw the nationalisation of Venezuela’s energy, mining, construction, telecommunications and other sectors. Chavez’ presidency set the stage for Evo Morales’ nationalisation of Bolivia’s hydrocarbon sector when he took office in 2006 and a trend towards nationalisations by Ecuador’s Rafael Correa.

2.2 Dwindling investor friendly policies

Investment in Latin America’s shale has also been challenged by governmental policies in some countries. For example, Argentina’s handling of its inflation figures, exchange rate restrictions, default on its international debt and general regulatory uncertainty are not conducive to foreign investments. Brazil’s policy focus on offshore pre-salt activities has deterred its shale gas development; its significant domestic content policies are also expected to unnerve some investors. In addition, some Latin American countries’ labour policies and price caps on the domestic market have also deterred potential investors in the shale industry.

2.3 Indigenous and environmental protests

Another reason some investors might shy away from investing in Latin American shale is because of the risk of indigenous and environmental protests. For example, in 2011 an Ecuadorian court fined Chevron over US$ 8 billion for alleged environmental and social damage to Ecuador’s Amazon region caused by Texaco, which Chevron acquired in 2001. The lawsuit was brought by around 30,000 Amazonian tribespeople and communities who claimed that above-average cancer rates and other severe problems were due to toxic waste-water/sludge being dumped into rivers supplying their drinking water. Although Chevron awaits a hearing from the international arbitration tribunal in The Hague on the claim, it has lost millions of dollars in production and fees.

Brazil’s proposed Belo Monte dam, which is being developed to provide hydroelectric power to the country, has also encountered significant opposition to its construction from indigenous and environmental groups. Indigenous groups protest against the harm they argue Belo Monte will bring to their way of life and environmentalists contend that the dam will unleash irreversible environmental consequences, such as greenhouse gas emissions and deforestation.

3. Looking forward

In order to develop its shale resources, Latin America will need to attract a significant amount of capital investment to finance the technology, infrastructure and human capital necessary to effect a US-style shale revolution. Investors will likely be attracted to the region’s economic growth, which is expected to propel natural gas use from 7.6 tcf/d in 2012 to 16 tcf/d in 2040, and its vast estimated technically recoverable shale gas reserves (around 1,431 tcf). The region’s coastal geography, which provides convenient avenues of export to European and Asian markets, is also attractive to investors. Moreover, some argue that Latin American governments’ and companies’ prior experience working with extractive industries should lower barriers to entry for shale development. However, the aforementioned nationalisation trend and indigenous and environmental protests in the region throw up obstacles to achieving the investment necessary to fully develop Latin America’s shale gas resources. This means that it will likely take more time for Latin America to achieve its shale gas revolution than it did for its North American neighbour.
4. Up-and-coming shale countries

Latin America – Shale Gas Resources

Note 1: This graph is based on unproved shale gas technically recoverable resources as per the EIA Report.

On the basis of the map and graph above, recent regulatory developments and our clients’ interests, we have identified Argentina as the country with the best prospect for shale gas development in Latin America. The next chapter will explore how Argentina’s legislation addresses some of the key contractual issues to consider for a shale gas project.
1. **Introduction**

1.1 **Industry background**

Argentina's oil and gas history dates back to the early 20th century when YPF, Argentina's NOC, was formed. Oil production in the country peaked in the late 1990s, with natural gas production starting to decline in the 2000s. Nevertheless, Argentina's demand for energy has remained strong.

Various explanations for the decline in Argentina's oil and gas production exist. The Argentine government has attributed the decline to underinvestment and excessive dividends at YPF, which was privatized in the early 1990s. Argentina relied in part on that rationale when it compulsorily acquired Repsol's majority stake in YPF in 2012. This government takeover may have deterred investment in Argentina's unconventional resources.

As of the end of 2013, compensation negotiations between YPF and Repsol began. It is hoped that the compensation deal to be negotiated will bolster investor confidence in Argentina's oil and gas sector and encourage the billions of dollars necessary to exploit Argentina's unconventional resources. Argentina has estimated reserves of technically recoverable shale gas resources of 802 tcf. These are the second largest reserves of shale gas resources in the world after China, according to the EIA Report.

1.2 **Legal framework**

In general terms, both in Argentina as a whole and the Province of Neuquén, where most of the shale gas activity is taking place, the same principles of conventional oil and gas regulation also apply to unconventional oil and gas activities. The main oil and gas regulations of the Province of Neuquén are:

- Hydrocarbons Law No. 2,453 of the Province of Neuquén ("Law");

- Provincial Executive Order No. 3,124 implementing Hydrocarbons Law No. 2,453 of the Province of Neuquén; and

- Provincial Executive Order No. 1,447/2012

One distinction between unconventional and conventional deposits is reflected in Executive Order No. 1,447/2012. This Executive Order establishes that if the holder of an exploration permit proves that it is not commercially feasible to exploit the hydrocarbons deposit located within the relevant exploration area, it may apply for an 'evaluation period' in order to assess the commercial potential of the deposit. Although not exclusively targeted at unconventional fields, this provision is more likely to apply to shale deposits, given that appraisal is more problematic. This extension period can be for one to five years. During this time, the permit holder must pay a fee of an amount equal to four times the exploration fee in the case of conventional deposits and seven times the exploration fee in the case of unconventional deposits.

In addition, in September 2013, a National Senator sent a draft bill to the National Congress to regulate the extraction of shale oil and gas through the hydraulic fracturing method ("Bill"). The Bill was sent for debate to the Commission of Environment and Sustainable Development and
the Commission of Mining, Energy and Fuels of the National Senate. As of January 2014, the Bill has not been debated.

1.3 Ownership of hydrocarbon resources

In 1994, the National Constitution was amended, transferring eminent domain over natural resources to the provinces. However, the amendment did not make any specific reference to who (i.e. the provinces or the federal government) had jurisdiction over those resources. As Article 1 of National Law No. 17,319 ("Hydrocarbons Law") provided that the ownership of hydrocarbon deposits belonged to the nation state, this situation caused conflicts between the provinces and the federal government over regulation in relation to natural resources. Most, but not all of such conflicts were overcome in 2007 when National Law No. 26,197 ("Short Law") was enacted, which effectively transferred ownership and authority to grant control of hydrocarbons to the provinces, save for offshore areas beyond the 12 mile limit of provincial jurisdiction.

1.4 Administration

Federal Administration of Oil & Gas Activities in Argentina

As shown in the schematic above, in Argentina, at the Federal level, the key players in the oil and gas sector are:

- **National Secretariat of Energy** ("Secretariat"). The Secretariat's role consists of:
  
  - enforcing the hydrocarbon regime at the federal level;
  - preparing the national energy policy;
  - controlling offshore concessions and permits beyond 12 marine miles; and
  - regulating the inter-provincial and cross-border transportation concessions, the hydrocarbon foreign trade and the liquefied petroleum gas market.
• **Commission on Strategic Planning and Coordination** ("Commission"). The Commission was established by Executive Order No. 1277/2012 and given the following tasks:
  o establishing a sanction regime;
  o setting a plan of minimum budget and investment goals;
  o maintaining the Registry of Hydrocarbon Investments;
  o controlling and approving investments plans of IOCs and NOCs in the hydrocarbon sector; and
  o publishing reference prices for the sale of hydrocarbons and fuels.

• **Federal Hydrocarbon Council** ("Council"). The Council was created pursuant to National Law No. 26,741. The Council's functions are to:
  o promote coordinated action by stakeholders regarding National Law No. 26,741 (i.e. the law calling for national self-sufficiency in hydrocarbons and expropriating 51% of YPF, hereafter "YPF Law");
  o guarantee compliance with YPF Law's purposes; and
  o establish a national hydrocarbon policy.

• **Ente Nacional Regulador del Gas** ("ENARGAS"). Established under National Law No. 24,076 ("Gas Law"), ENARGAS is a regulatory authority whose functions are to regulate the transportation, distribution, commercialisation and storage of gas.

• **Federal Organisation of United Oil Products** ("OFHEPI"). OFHEPI is an organisation composed of the federal government and the oil producer provinces. OFHEPI jointly represents the common interests of the oil producer provinces in respect of the exploration and exploitation of the hydrocarbons reserves located within their territories.

• **Energía Argentina Sociedad Anónima** ("ENARSA"). Created pursuant to Law No. 25,943, ENARSA is a partially state-owned company (53% national state, 12% provincial governments and 35% traded on the stock market). ENARSA has ownership of all offshore concessions and permits, which are located within 12 to 200 nautical miles and that were not subject to a concession at the time of their creation. ENARSA calls for bids in these offshore areas and is also in charge of the LNG program.

• **YPF S.A.** YPF is an NOC (51% national states and 49% provincial governments). YPF currently is the sole holder of exploration and production rights and is also associated with provincial owned companies ("POCs") and IOCs. YPF is in a privileged situation as it is the right holder of most of the areas with unconventional potential in the Province of Neuquén.
As shown in the schematic above, in Argentina the provincial governments perform the following functions:

- granting exploration and exploitation concessions and permits;
- imposing and collecting royalties and taxes;
- granting transportation concessions within their territory; and
- regulating hydrocarbons exploration and production within their territory.

The sections below will concentrate on Federal regulations and the regulations of the Province of Neuquén.

2. **Key contractual issues for a shale gas project**

2.1 **Exploration term**

A distinction is drawn between the following categories of areas (Articles 10 and 22 Law):

- **Proven** - These are areas which reflect sedimentary or stratigraphic traps where the existence of potentially commercially exploitable hydrocarbons has been established. No exploration permits are granted in these areas.

- **Of secondary interest** - This category deals with areas that contain oil and gas reserves but:
  
  o are inactive;
  
  o have reverted to the provincial government; or
  
  o come from abandoned tenders.

No exploration permits are granted in these areas.

*This schema focuses on the Neuquén and Santa Cruz which have the largest shale gas plays.*
• **Possible** - These are areas not included in the "Proven" and "Of secondary interest" categories. Exploration permits are granted as follows:
  - First period, up to four years;
  - Second period, up to three years; and
  - Third period, up to two years.
This means that a permit can be granted for a total of nine years in possible areas.

• **High-risk exploratory** - This category contains areas that present significant geological complexity. Exploration permits are granted as follows:
  - First period, up to six years;
  - Second period, up to four years; and
  - Third period, up to three years.
Permits can therefore be granted for a total of 13 years in high risk exploratory areas.

For all categories:
• an extension period of up to one year is available at the election of the permit holder, who must justify it on technical grounds;
• the minimum exploration permit area is 100 km² (Article 23 Law); and
• the maximum exploration permit area is 100,000 km² (Article 24 Law).

2.2 Relinquishments

Article 25 Law provides that upon completion of:
• the first period, the permit holder shall relinquish 50% of its permit area;
• the second period, the permit holder shall relinquish 50% of the remaining permit area;
• the third period, the permit holder shall return the entire remaining area, unless it exercises the right to use the extension period. In this case, the permit holder shall relinquish 50% of the remaining area.

2.3 Exploitation term

Exploitation concessions are granted for 25 years (Article 34 Law), plus any unelapsed period of the exploration permit (Article 22 Law). Article 34 Law further provides that exploitation concession can be extended for up to 10 years.

2.4 Delineation exploitation concession

Pursuant to Article 32 Law, "To the extent possible, each of the parcels covered by a concession should match up with all or part of the commercially exploitable oil and gas productive traps". Article 32 further states that the boundaries of each block may not exceed the area retained under the exploration permit.

If an exploitation concession does not result from an exploration permit, the exploitation concession area may not exceed 250 km² (Article 33 Law).
2.5 NOC participation and carry

Save for the *de facto* compulsory participation of ENARSA in offshore exploration permits and concessions licences, there is no requirement as to a compulsory minimum state participation at the Federal level. However, pursuant to Article 12 Law, the Province of Neuquén shall, if it so determines, receive a participatory share (payable in cash or, exceptionally, in kind) of the products of the exploitation activity.

In addition, Article 114 Law provides that some areas may be reserved for exploration/exploitation by state-owned companies (i.e. at the provincial level, these are generally the POCs). Private companies can associate with state-owned enterprise to work on the areas reserved for state-owned companies. The state-owned company percentage participation interest will be determined in the association contract (Article 118 Law). In 2010, consortiums led by YPF were awarded most of the areas offered for hydrocarbon exploration in Neuquén in association with Neuquén's POC (Gas y Petróleo de Neuquén). Therefore, IOCs will need to enter in a JV with YPF and Gas y Petróleo to conduct exploitation for unconventional exploration in Neuquén.

2.6 Water resources rights

Companies that need to use large quantities of water to develop a project (for example, an unconventional hydrocarbons project) must obtain a permit from the relevant provincial hydrologic authority. In the Province of Neuquén, the authority in charge of granting such permits is the Hydrologic Resources General Office.

In addition, the Bill includes regulations on the use of water. In particular, it prohibits the use of groundwater that could be destined for human consumption and/or soil irrigation during the drilling and closure of wells stages in unconventional hydrocarbons projects.

2.7 Flaring

Flaring is regulated both at the Federal (Resolution No. 236/1993 and Resolution No. 143/1998 of the Secretariat of Energy) and provincial levels.

In the Province of Neuquén, the flaring and venting of gas is regulated by Law No. 2,175 and Executive Order 29/2001. In essence, these regulations provide the following:

- the release of gas must always be authorised by the Sub-Secretariat of Energy of Neuquén;
- if gas is released into the atmosphere, such gas must be flared;
- the release of gas into the atmosphere at gas wells is prohibited;
- for oil and gas wells, as from January 1st, 2000, only one cubic meter of gas per cubic meter of oil can be released into the atmosphere;
- release and flaring of gas at oil and gas wells in excess of the limit indicated above is highly restricted and exceptionally allowed on a case by case basis and for a limited period of time only, provided the operator or concessionaire of the relevant deposit files a presentation with the Sub-Secretariat of Energy of Neuquén justifying the need to release and flare gas in excess of such limit;
- for oil and gas wells, the gas released in excess of the legal limit is subject to the payment of a fee for atmospheric contamination equivalent to 500% of the average sale price of natural gas at well heads in the Province of Neuquén;
• the release of gas at oil and gas wells requires the filing of a monthly sworn statement with the Sub-Secretariat of Energy of the Province of Neuquén providing information on the quantity of gas released from the wells; and

• release and flaring of gas activities must comply with the national and provincial environmental protection regulations (e.g. National Environmental Law No. 25,675 and Provincial Environmental Law No. 1,875).

2.8 Economic stabilisation

Federal laws do not provide for stability provisions. However, in the Province of Neuquén, Article 58 Law provides that for the duration of the permits and concessions, the holder of exploration permits and exploitation concessions shall pay all of the provincial and municipal taxes and duties that are in force on the date of the award. It further provides that the Province of Neuquén may not tax titleholders with new taxes or increase existing ones, except for overall increases in provincial taxes, those collected by the national government or taxes that replace the latter.

3. Other contractual issues to consider

3.1 Domestic market obligations

In the Province of Neuquén, subject to Article 12 Law (right of the Province of Neuquén to receive a share of the hydrocarbons produced), owners of exploitation rights are free to dispose of the hydrocarbons they extract. These hydrocarbons may be transported, processed, and marketed, along with their derivatives, notwithstanding compliance with the regulations issued by the Provincial Executive Branch (i.e. the Governor of the Province of Neuquén) on technical/economic bases that seek a reasonable degree of fluidity in the supply and profitability on the domestic market and stimulate exploration and exploitation of hydrocarbons (Article 6 Law).

There are DMO at the Federal level in Argentina:

• pursuant to Article 6 Hydrocarbons Law:
  o when the domestic production of liquid hydrocarbons is not sufficient to cover internal needs, all hydrocarbons of domestic origin shall be made available for use in the domestic market, save when technical reasons make this unadvisable;
  o the production of natural gas may be used, firstly, for the exploitation of the reservoirs from which it is extracted and of others in the area, whether or not they belong to the concessionaire. Secondly, any state-owned company that provides a gas distribution service has a preference right to acquire, within acceptable periods of time, any amounts in excess of the first use at agreed prices, provided that such prices shall ensure a fair rate of return on the investment involved and taking into account the special characteristics and conditions of the reservoir; and
  o the marketing and distribution of gaseous hydrocarbons is subject to regulations issued by the National Executive Branch. Currently, natural gas exports can only be made after domestic demand is satisfied.

• Whilst there are no specific restrictions on crude oil exports, export taxes (e.g. Resolution No. 394/2007), which vary according to international oil prices, effectively set a "ceiling" on the producers' share of export income.
The table below sets out how the Federal law addresses some of the issues to be considered by IOCs if DMO are applicable:

<table>
<thead>
<tr>
<th>Issues</th>
<th>Argentinian Regime</th>
</tr>
</thead>
<tbody>
<tr>
<td>DMO extent</td>
<td>The Executive Branch has the discretion to require that all hydrocarbons of domestic origin shall be made available for use in the domestic market (Article 6 Hydrocarbons Law).</td>
</tr>
<tr>
<td>Shale gas exports</td>
<td>The Executive Branch shall allow the exportation of any hydrocarbons or products not required for the adequate satisfaction of domestic needs, provided that these exports are made at reasonable commercial prices (Article 6 Hydrocarbons Law).</td>
</tr>
<tr>
<td>Sale price of gas sold in the domestic market</td>
<td>During any period in which the domestic production of liquid hydrocarbons is not sufficient to cover internal needs, the Executive Branch can set the prices for the marketing of crude oil in the domestic market. If it does so, such prices shall be equal to those established for the respective state-owned company that charged in transactions with third parties, but not less than the price levels for imported oil on similar terms and conditions. However, if the prices for imported oil increase significantly because of exceptional circumstances, they shall not be considered in setting prices for marketing in the domestic market, and in such event, they may be set based on the state-owned company’s actual costs of exploitation, any depreciation that is technically appropriate, and a reasonable rate of return on any investments that such state-owned company may have made, adjusted for inflation and depreciated (Article 6 Hydrocarbons Law).</td>
</tr>
<tr>
<td>Repatriation of proceeds and profits</td>
<td>On 25 October 2011, Executive Order No. 1722/2011 established the obligation to repatriate 100% of export proceeds for companies producing crude oil and any by-products, natural gas and liquefied gas.</td>
</tr>
<tr>
<td>Definition of domestic market</td>
<td>There is no definition of “domestic market” provided in the legislation.</td>
</tr>
</tbody>
</table>

3.2 Fiscal regime and tax incentives

In the Province of Neuquén, Article 61 Law provides that once a month, the holder of an exploitation concession shall pay to the provincial government, as a royalty on the production of the liquid hydrocarbons extracted from the wellhead, a percentage consisting of 12%. The Provincial Executive Authority may reduce such percentage to 5%, taking into consideration the productivity, conditions and location of the wells.

In Argentina there are no tax breaks or investment incentives to incentivise investments in depleting fields.

3.3 Third party and state access to infrastructure

Pursuant to Article 42 Law, subject to the satisfactions of the concessionaire’s needs, when:

- facilities have excess capacity; or
- there are no technical reasons that would prevent it,
the concessionaire is obliged to transport oil and gas for third parties without discrimination against any persons, at the same price under identical circumstances.

Article 42 Law further states that should the provincial government opt for payment of the royalty in kind (as per Article 67 Law), the concessionaires will have to provide the provincial government with the transmission capacity needed for the purposes of transporting the volumes to be delivered as payment of the royalty in kind.

4. Market update

4.1 Recent developments

Currently, there is no shale gas project in production in Argentina. However, there are great expectations in relation to the "Vaca Muerta" shale gas project located in the Province of Neuquén. This project has one of the largest estimated shale gas reserves in the country. YPF (the holder of the project's rights) is executing several agreements with different companies (such as Chevron, Dow Chemical and Petronas) to perform exploration activities in the "Vaca Muerta" deposit.
4.2 Key shale basins

The EIA identified the following basins as having technically recoverable shale gas resources in Argentina:

Argentina Shale Gas Basins

4.3 Companies

The following companies are currently involved in shale gas operations in Argentina:

<table>
<thead>
<tr>
<th>Company</th>
<th>Activity</th>
</tr>
</thead>
<tbody>
<tr>
<td>YPF/Dow Chemical</td>
<td>Agreement to explore in Neuquén. YPF had drilled 60 wells by November 2012.</td>
</tr>
<tr>
<td>ExxonMobil, Apache, Chevron, EOG,</td>
<td>Expressed an interest in the Vaca Muerta field in Neuquén.</td>
</tr>
<tr>
<td>Royal Dutch Shell, Total, Americas</td>
<td></td>
</tr>
<tr>
<td>Petrogas and Madalena Venture</td>
<td></td>
</tr>
<tr>
<td>Company</td>
<td>Activity</td>
</tr>
<tr>
<td>-------------------------------</td>
<td>--------------------------------------------------------------------------</td>
</tr>
<tr>
<td>YPF/Cnooc Ltd/Bridas Corp</td>
<td>Agreement to explore in Neuquén.</td>
</tr>
<tr>
<td>YPF/Chevron</td>
<td>Agreement to explore in Neuquén.</td>
</tr>
<tr>
<td>Wintershall/Gas &amp; Petróleo de Neuquén</td>
<td>Agreement to explore and develop a block in the Vaca Muerta field.</td>
</tr>
</tbody>
</table>

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North America

1. Introduction

Shale gas resources are abundant in North America, with the EIA ranking the US, Canada and Mexico as the fourth, fifth and sixth countries with technically recoverable shale gas resources in the world at 665 tcf, 573 tcf and 545 tcf, respectively. North America is also the region producing the most shale gas in the world. This is largely due to shale gas exploration and production efforts in the US.

As depicted in the map below, both the US and Canada have welcomed the exploration and production of their shale basins while Mexico is still assessing its shale gas potential and policy. To date, commercial production of shale resources in Canada has not yet achieved the scale seen in the US, and Mexico's shale gas development has been constrained in large part because of a lack of investment, with Petróleos Mexicanos (PEMEX), Mexico's NOC, allocating only a small portion of its budget to shale gas exploration and development.

2. Key challenges for a shale gas revolution in North America

2.1 Local opposition

As in other regions, the development of shale resources in North America has been opposed by some. Anti-fracking activists and coalitions of environmental groups have advertised and
protested against the perceived negative impacts that shale development has on water, air and seismic stability (e.g. the recent protests in New Brunswick, Canada, where 96 people have been arrested since July 2013 for interfering with SWN Resources Canada's seismic mapping of shale gas basins). In the US, protesters' voices have been heard by some lawmakers most notably in California and New York, where legislation against hydraulic fracturing has been adopted. For example, New York State, located above the Marcellus shale basin, has had a moratorium on fracking since 2008, and anti-fracking activists consistently urge the state's Governor Andrew Cuomo to expand the moratorium. Likewise, Santa Cruz County, California, has banned fracking for oil largely due to the fear that such activity would pollute the area's aquifers. Some perceive this legislation as a bad sign for fracking in California, whose Monterey Shale has the most shale oil in the US with estimates around 15.4 billion barrels.

2.2 Keeping pace

Another challenge for North America's shale gas revolution is to keep pace with the gains made so far. As new gas from fracking has been placed into the market, gas prices in the US have fallen to less than US$ 4 per million British thermal units ("BTU"). Since around US$ 6 per BTU is needed to cover all the costs over a well's life cycle, some wonder to what extent the lower gas prices will discourage further investment into US shale gas. One thing is certain: a clear trend has emerged in the US whereby companies are shifting their exploration and development operations from shale gas plays (such as the Barnett) to liquid-rich shale plays (e.g. Eagle Ford and Bakken). These liquid-rich shale plays produce oil and natural gas liquids; products which are trading at much higher prices in the US than natural gas.

North America's transportation infrastructure also needs to keep pace with its shale gas revolution. The increasing use of rail to transport oil in North America has raised safety concerns, including those arising from the derailment of a train carrying Bakken formation crude oil in Quebec in July 2013, which killed 47 people. Canada's Keystone Pipeline System is intended to bolster Canada's limited pipeline infrastructure. In addition, Mexico's energy reform, which was signed into law in December 2013, is expected to yield more investment in infrastructure throughout the country.

3. Looking forward

The effects of North America's shale gas revolution are wide-ranging. Shale gas has boosted the overall economy in the US, provided jobs and reduced household energy bills for many Americans. Shale gas is also changing the US' industrial landscape. For example, chemical companies have been switching from using oil as a feedstock to using shale gas, a much cheaper fuel. The electricity industry has been replacing dirtier coal-fired power plants with cleaner gas-fired power plants. Similarly, the steel, aluminium and iron heavy industries are increasingly turning to natural gas in their fabrication processes. Businesses that support the shale industry, including road and port-building companies, are also seeing a boost. In addition, shale gas is leading to the conversion of some US LNG terminals from import to export terminals. Last but not least, US shale production is expected to drive the US beyond Russia and Saudi Arabia as the world's top oil producing country by 2015. This, along with the predicted increase in converting US shale gas into LNG for export, will have a geopolitical impact on other regions and the world at large.
4. Up-and-coming shale Countries

North America – Shale Gas Resources

On the basis of the map and graph above, recent regulatory developments and our clients’ interests, we have identified the US as the most auspicious country for shale gas development in North America.
America. The next two chapters will explore how legislation in the US addresses some of the key legal issues to consider for a shale gas project.
1. Introduction

1.1 Industry background

According to the EIA, domestic production of oil and natural gas in the US is expected to continue to grow, which will likely decrease US demand for imported fuels. By 2016 domestic oil production is predicted to come close to the historical high achieved in 1970 of 9.6 million bpd and then level off and slowly decline after 2020.

New applications of hydraulic fracturing technology and horizontal drilling are offsetting declines in production from conventional gas reservoirs. Natural gas production is expected to grow steadily with a 56% increase between 2012 and 2040, which is around the same year natural gas is predicted to overtake coal in providing the largest share of electric power generation in the US. The EIA predicts that higher natural gas production will support increased exports of both pipeline gas and LNG. Moreover, it is anticipated that an increased supply of natural gas liquids will benefit the petrochemical industry in the US.

The development of the oil and gas industry in the US is not without its critics. Some environmentalists oppose hydraulic fracturing because of its use of and alleged impact on water and perceived linkage to seismic activity, among other reasons. The Keystone XL Pipeline intended to transport primarily synthetic crude oil from Canada’s oil sands in Alberta through the US to the Gulf Coast of Texas, is also opposed by some on environmental grounds.

1.2 Legal framework

There are elements of shale gas legislation at both state and federal levels. The prominent shale producing states are Texas, Louisiana, North Dakota and Pennsylvania (“Key Shale States”) and, to a lesser extent, Oklahoma, Arkansas, West Virginia, and Ohio. Each have their own legislation and regulatory agencies governing oil and gas exploration, and federal law places additional environmental restrictions on production.

In general, states regulate operations for oil and gas, including toxic chemical disclosure, water use and disposal and contamination. The federal government sets air and water pollution standards (through various laws, including the Safe Drinking Water Act, Clean Water Act, Clean Air Act and Resource Conservation and Recovery Act), which are enforced by the Environmental Protection Agency.

The following paragraphs provide an overview of key legislation and regulations affecting production from shale formations in the US.

1.3 Ownership of hydrocarbons

The US is unique among major oil and gas producing nations in that most minerals in the US are privately owned. As a result, the terms of most agreements for exploration and development of oil and gas are determined by private contracts that are freely negotiated between mineral owners and exploration and production companies. However, state and federal laws, particularly regulations regarding hydraulic fracturing, horizontal drilling and environmental standards, may still impact oil and gas production from shale formations.
1.4 Administration

Federal Administration of Oil & Gas Activities in the US

As shown in the schematic above, in the US, at the federal level, the key regulators in the oil and gas sector are:

- **Environmental Protection Agency** ("EPA"). The EPA is an independent federal agency that maintains and enforces environmental laws and conducts environmental assessments, research and education, all with the purpose of reducing pollution and protecting human health and the environment. It is the arbiter of national standards under a variety of environmental laws, although it delegates some monitoring, enforcement and permitting responsibilities to US states and federally recognised Native American tribes. The EPA is conducting a study of hydraulic fracturing ("Fracking Study") and its potential impact on drinking water resources, a draft of which it hopes to release for public comment and review in 2014.

- **Federal Energy Regulatory Commission** ("FERC"). FERC is an independent federal agency that regulates interstate oil and gas pipelines and pricing, as well as the transmission and pricing of interstate electricity and hydroelectric projects and licensing. FERC also reviews and authorises LNG terminals, including the conversion of LNG import terminals into export terminals. LNG export terminals will also require a licence to export from the DOE. FERC is also the governmental agency responsible for permitting the new interstate gas gathering and transmission pipelines needed as a result of the shale gas boom.

- **Department of Energy** ("DOE") and **Office of Fossil Energy** ("OFE"). The DOE is a Cabinet-level executive agency of the federal government. One of its three major programs is the energy program. The DOE’s energy program comprises five offices, one of which is the OFE. The OFE supports research and development programs related to fossil fuels. The DOE Shale Gas Program is a collaboration between the OFE and other federal and state agencies, industry, academia and NGOs committed to advancing oil and gas exploration and production technologies in an effective, safe and environmentally sustainable manner. OFE is a contributor to the EPA’s Fracking Study.
• **Bureau of Land Management ("BLM")**. The BLM is an agency within the US Department of the Interior that manages around 245 million surface acres of public lands and around 700 million acres of subsurface mineral estates. BLM is in charge of the permitting and licensing process for companies to explore and produce oil and gas on federal lands. Once a project is approved, BLM is the agency that ensures that use authorisation requirements and regulations are complied with. Accordingly, fracking operators and developers are closely monitoring whether the BLM will expand federal oversight of fracking on federal lands by requiring further disclosure of hydraulic fracturing fluids and water management plans, which many believe are already adequately addressed by state regulations.

• **Bureau of Indian Affairs ("BIA")**. The BIA is an agency within the US Department of the Interior that manages the 55 million surface acres of land and 57 million acres of subsurface minerals estates held in trust by the US for Native Americans. The BIA issues mineral leases on Native American lands, but the BLM approves and supervises mineral operations on those lands.

**State Administration of Oil & Gas Activities in the Key Shale States**

As shown in the schematic above, in the US, at the state level, the key regulators in the oil and gas sector are:

• **North Dakota**

  The Department of Mineral Resources’ Oil and Gas Division ("OGD") regulates the drilling and production of oil and gas in North Dakota. More specifically, OGD administers the laws and regulations relating to the drilling and plugging of wells, the restoration of drilling and production sites, saltwater and oil field waste disposals, well spacing and the filing of reports on well location, drilling, and production. North Dakota’s Pipeline Authority, is the North Dakota Industrial Commission, which was created in 2007 to develop the state’s pipeline facilities to support transportation of North Dakota energy-related commodities, much of which comes from the Bakken formation.

• **Louisiana**

  The Department of Natural Resources ("DNR") is a department under the executive branch of Louisiana’s state government. Its mission is to preserve and enhance the state’s non-
renewable resources including oil and gas, which resources are specifically overseen by the Office of Conservation and the Office of Mineral Resources. The Office of Conservation has six divisions responsible for implementing the state’s oil and gas rules and regulations; its Engineering-Regulatory division inspects oil and gas wells; its Injection & Mining division implements the Underground Injection Control program; and its Pipeline division regulates the intrastate natural gas pipeline operators and network. The Office of Mineral Resources has four divisions responsible for implementing the state’s oil and gas rules and regulations, one of which is the Petroleum Lands Division responsible for managing mineral leasing for the state.

• **Pennsylvania**

The Office of Oil and Gas Management ("OOGM") is a division of the Pennsylvania Department of Environmental Protection. OOGM develops policies, standards and programs for and regulates/enforces the development and production of oil and gas in Pennsylvania pursuant to the state's laws. With respect to the Marcellus Shale gas reservoirs, OOGM is the agency that reviews and issues drill permits, inspects drilling operations and responds to water quality and other complaints. OOGM also conducts training programs for the industry and works with the Interstate Oil and Gas Compact Commission and the Technical Advisory Board.

• **Railroad Commission of Texas**

The Railroad Commission of Texas ("RRC") is the state agency that regulates the oil and gas industry, the liquefied petroleum gas industry, surface mining for coal and uranium, gas utilities and safety for pipelines. The RRC sets allocations for production in Texas each month and adopted hydraulic fracturing water recycling rules in spring 2013.

2. **Regulations on hydraulic fracturing in key US states**

The US does not currently regulate hydraulic fracturing at the federal level. Instead, states play the main role in regulating hydraulic fracturing, primarily through regulations regarding oil and gas wells.

**Overview of restrictions on hydraulic fracturing and disclosure requirements in key US states**

<table>
<thead>
<tr>
<th>State</th>
<th>Play</th>
<th>Restrictions on Hydraulic Fracturing</th>
<th>Disclosure of Frack Fluids</th>
</tr>
</thead>
<tbody>
<tr>
<td>Arkansas</td>
<td>Fayetteville</td>
<td>Permit required before hydraulic fracturing can be used</td>
<td>Report types, volumes and concentrations of fluid, proppant and additives</td>
</tr>
<tr>
<td>Louisiana</td>
<td>Haynesville</td>
<td>N/A</td>
<td>Disclose fluids within 20 days of hydraulic fracturing operation completion</td>
</tr>
<tr>
<td></td>
<td>Tuscaloosa Marine</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Maryland</td>
<td>Marcellus</td>
<td>De facto Moratorium</td>
<td>Provide list of drilling additives, including toxicity and volume</td>
</tr>
<tr>
<td></td>
<td>Utica</td>
<td></td>
<td></td>
</tr>
<tr>
<td>New York</td>
<td>Marcellus</td>
<td>Moratorium</td>
<td>Provide statement of volumes of fluids injected and produced, plus other relevant data as may be required</td>
</tr>
<tr>
<td></td>
<td>Utica</td>
<td></td>
<td></td>
</tr>
<tr>
<td>State</td>
<td>Play</td>
<td>Restrictions on Hydraulic Fracturing</td>
<td>Disclosure of Frack Fluids</td>
</tr>
<tr>
<td>------------</td>
<td>------------</td>
<td>--------------------------------------</td>
<td>-----------------------------</td>
</tr>
<tr>
<td>North Dakota</td>
<td>Bakken</td>
<td>N/A</td>
<td>Submit description of proposed injection program (including average and maximum rate of fluids to be injected and quantity of materials used) prior to operation</td>
</tr>
<tr>
<td>Ohio</td>
<td>Marcellus Utica</td>
<td>N/A</td>
<td>Report type, volume and concentration of acid (if applicable), and type and volume of fluids</td>
</tr>
<tr>
<td>Oklahoma</td>
<td>Woodford Fayetteville</td>
<td>Permit required before hydraulic fracturing can be used</td>
<td>Submit description of injection medium, sources and estimated amounts to be injected prior to enhanced recovery only</td>
</tr>
<tr>
<td>Pennsylvania</td>
<td>Marcellus Utica</td>
<td>Moratorium in some watershed areas and river basins</td>
<td>Submit Preparedness, Prevention and Contingency Plans and well completion reports listing chemicals or additives used, quantities used and method of storage</td>
</tr>
<tr>
<td>Texas</td>
<td>Barnett Haynesville Eagle Ford</td>
<td>N/A</td>
<td>Disclose type of fluids within 30 days of well completion</td>
</tr>
<tr>
<td>Vermont</td>
<td>N/A</td>
<td>Banned</td>
<td>N/A</td>
</tr>
<tr>
<td>West Virginia</td>
<td>Marcellus Utica</td>
<td>Permit required before hydraulic fracturing can be used</td>
<td>N/A</td>
</tr>
</tbody>
</table>

Currently hydraulic fracturing is allowed in every state shown in the above table except Vermont, which has completely banned the procedure, and New York, which has declared a moratorium on the procedure pending the completion of an environmental impact study. Additionally, although Maryland does not have a ban on hydraulic fracturing, the state has refused to grant new permits for activities involving hydraulic fracturing, causing a de facto moratorium. However, shale plays in such states are minimal or non-existent.

Among the Key Shale States, hydraulic fracturing is generally allowed, although various municipalities have enacted local bans, and Pennsylvania has a moratorium in effect in certain watershed areas and river basins. Additionally, states such as Oklahoma, Arkansas, and West Virginia have enacted rules specifically to regulate hydraulic fracturing by requiring oil and gas operators to acquire permits before using hydraulic fracturing on wells.

Many states have enacted additional regulations regarding the disclosure of fluids used in hydraulic fracturing. Texas, for example, requires disclosure of the type of injection fluid used within 30 days after completion of a well. Louisiana requires disclosure of the ingredients used in injection fluid no later than 20 days following the completion of hydraulic fracturing stimulation operations. Other states require disclosure before hydraulic fracturing begins. In total, 20 states...
currently require some form of either public or regulatory disclosure of injection fluids, and several other states are considering regulations.

3. **Regulating cross-unit lateral wells**

Horizontal drilling for shale has drawn attention to the rights of operators to drill across property or lease lines, even when they do not have the express contractual right to do so. States have taken various approaches to these issues (i.e. forced pooling or lease integration).

### Drilling across property lines an overview in key US states

<table>
<thead>
<tr>
<th>State</th>
<th>Force Pooling Laws, Leases Integration, Allocation Wells or Other</th>
<th>Risk Penalty</th>
</tr>
</thead>
<tbody>
<tr>
<td>Arkansas</td>
<td>Force pool</td>
<td>N/A</td>
</tr>
<tr>
<td>Louisiana</td>
<td>Force pool</td>
<td>200% of the well’s drilling and completion costs</td>
</tr>
</tbody>
</table>
| North Dakota    | Force pool                                                      | Working interest owners: 200% of drilling and completion costs  
Mineral owners: 50% of drilling and completion costs |
| Ohio            | Force pool                                                      | 200% of drilling and completion costs            |
| Oklahoma        | Force pool                                                      | N/A                                              |
| Pennsylvania    | Lease Integration                                               | N/A                                              |
| Texas           | Allocation Wells                                                | N/A                                              |
| West Virginia   | Considering a mixture between force pool and lease integration   | Determined by Department of Environmental Protection: between 200% and 300% of drilling and completion costs |

3.1 **Forced pooling**

Certain states, such as North Dakota, Oklahoma, Louisiana, Arkansas and Ohio, have laws granting the operator the right to "force pool" interest owners who have not otherwise authorised the operator to develop the lands as a unit.

Generally, in order for an operator to obtain an order creating a forced pooled unit, the operator must:

- apply to the state regulatory authority and show that operating the field as a unit will prevent waste and protect correlative rights; and
- obtain the consent of a certain percentage of the interest owners in the area to be developed.

For example, in Louisiana, an internal memorandum for staff of the Office of Conservation in the Department of Natural Resources provides that applicants for cross-unit lateral wells in shale formations must provide written evidence that the majority of owners having the right to drill (including working interest owners, and, if applicable, leased landowners and unleased mineral owners) for each unit penetrated by the proposed horizontal well, including all current unit operators for such units, consent to the drilling of the horizontal well.
In those cases in which an interest owner does not consent or chooses not to participate in the drilling costs of the well, that owner is usually required to pay the operator a risk penalty out of production. This risk penalty varies by state. As an example, in Louisiana, an interest owner choosing not to elect to participate in the drilling and completion costs is required to pay out of production a risk penalty of 200% of the well's drilling and completion costs before the interest owner is entitled to receive any proceeds from the well.

3.2 Lease integration

Other states, such as Pennsylvania, have laws granting the operator the ability to "integrate" leases. Under this approach, the operator must already have existing leases that authorise the right to develop the property, and the leases must not expressly prohibit joint development of the property with adjacent properties. Additionally, these statutes may provide for a method of allocating royalties among the leased tracts (for example, Pennsylvania’s statute provides that, in the absence of an agreement, production is allocated to each lease as reasonably determined by the operator).

3.3 Alternative approaches

Some states, such as West Virginia, are in the process of considering variations of forced pooling or lease integration laws.

Finally, there are some states that take neither of the above two approaches and, as a result, have begun issuing permits for the drilling of "allocation wells." Allocation well permits allow the operator to drill a well across lease lines where the operator owns the leases on both sides of the line. The operator will then allocate the production to each tract according to some previously determined method. The particular method used to allocate the production amongst the owners on the multiple tracts must be reasonable. However, parties may disagree about the proper allocation method for a particular well. For example, some parties may argue that production from the allocation well should be allocated based on the portion of the lateral length of the well that crosses each tract. Other parties may argue that instead of the entire lateral length, only the interval between the first perforation point and the last perforation point on the lateral should be used for allocation purposes, since that is the actual producing interval. In a recent case before the Texas Railroad Commission, an operator's application for an allocation well was approved despite the lack of pooling authority in the leases covering the tracts traversed by the proposed well. While such an outcome is beneficial for operators conducting horizontal drilling in Texas, many questions may still remain in Texas courts regarding operations on allocation wells.

4. Permitting process for drilling wells in Key Shale States

All of the Key Shale States require an oil and gas operator to obtain a permit from the state's regulatory agency governing oil and gas exploration before drilling. The regulatory agencies for the oil and gas industry in the Key Shale States and other prominent shale-producing states are:
While the requirements for permit applications vary by state, applications typically require:

- information about the proposed well's location, construction, and operation;
- an application fee;
- site and operational plans; and
- security or bond.

In some instances, in addition to reviewing the application for regulatory compliance, a state agency may require a site inspection before approving an application.

Other activities, such as seismic operations, well deepening operations, re-entry, and enhanced recovery operations also require separate permits in many states. Additionally, in some situations, supplemental permitting may be required in local ordinances, particularly in certain urban areas or regions with high exploration activity. Local permits may cover issues such as noise level, well placement, traffic and site maintenance, amongst others.

5. **Regulating water usage and disposal**

5.1 **Water usage**

Operations involving hydraulic fracturing require large amounts of water to be injected into the target shale formation. As a result, such operations often utilise water from freshwater sources regulated by a state or regional/interstate water authority. States' restrictions on water usage may be limited to pre-withdrawal estimates, or may include more onerous application and approval processes.

5.2 **Water disposal**

Once hydraulic fracturing operations end, flowback fluids and brine rise back up to the surface. These waste fluids are typically held in pits or tanks which are also subject to permitting requirements. All states require operators to obtain permits before building waste storage facilities and regulate the materials, dimensions, and storage methods of such facilities.
Operators must submit periodic reports throughout the life of such waste storage facilities. Many states will also require that waste storage facilities be a specified distance from bodies of water and residences.

After treatment at a wastewater treatment facility, flowback fluid and other waste from the hydraulic fracturing process may be injected into disposal wells, discharged into surface water, or reused in a fractured well. Injection into disposal wells is the most widely used method of disposal. If the operator intends to inject the wastewater into a disposal well, the operator will need to obtain a permit for the disposal well. Alternatively, the operator may contract with a third party disposal well operator to dispose of its wastewater.

6. Federal environmental laws and regulations impacting shale operations

The federal government sets air and water pollution standards and hazardous waste management and clean-up requirements under several statutes, including:

- the Safe Drinking Water Act ("SDWA");
- the Clean Water Act ("CWA");
- the Clean Air Act ("CAA");
- the Resource Conservation and Recovery Act ("RCRA"); and
- the Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA").

These laws are enforced by the US Environmental Protection Agency ("EPA"), unless authority is expressly delegated to relevant state agencies.

There has been significant and growing interest in air, water, and waste issues related to hydraulic fracturing in shale plays in the US, including expanding regulation at the state level and debate around the appropriate role of the federal government. The regulatory environment remains extremely fluid with respect to the nature and extent of pollution control requirements for hydraulic fracturing operations at both the state and federal level.

6.1 CAA

The EPA and state agencies with delegated authority regulate air emissions from the oil and gas industry under the CAA. In 2012, the EPA issued the first CAA regulations for hydraulic fracturing operations. These regulations impose significant new technology requirements for controlling wellhead emissions of volatile organic compounds ("VOCs"). There is also increasing interest in regulation of methane emissions from hydraulic fracturing operations based on the high Global Warming Potential ("GWP") of the gas, although the EPA has noted that its recently adopted VOC control requirements will greatly reduce the amount of methane released from fracturing wells.

6.2 SDWA

Hydraulic fracturing operations that do not utilise diesel fuel as an additive in fracturing fluids are exempt from federal regulation of underground injection wells under the SDWA. The US Congress has repeatedly considered legislation that would end this exemption and subject hydraulic fracturing wells to federal regulation under the SDWA, but to date these legislative efforts have been unsuccessful. The EPA is currently undertaking a comprehensive study of the impact of fracturing operations on drinking water that is expected to be completed in draft form.
by 2014. The results of this study may inform future congressional decision-making about whether to maintain the SDWA exemption for fracturing wells.

6.3 RCRA and CERCLA

RCRA and CERCLA respectively deal with the management of hazardous waste and liability for releases of hazardous substances. These laws also exempt key categories of substances and waste generated by hydraulic fracturing operations.

Crude oil and fractions of crude oil are excluded from regulation under both laws, while the definition of hazardous waste under RCRA excludes “drilling fluids, produced waters and other wastes associated with the exploration, development or production of crude oil, natural gas or geothermal energy”. Despite these exclusions, in recent years the EPA has sought to utilise certain emergency response authorities under CERCLA in particular to respond to potential threats to human health and the environment posed by fracturing operations.

6.4 CWA

Wastewater treatment plants that receive produced waters from fracturing operations are regulated under the CWA. Many state agencies with delegated authority to implement CWA requirements have sought to impose more stringent discharge limits on treatments plants receiving wastewaters from fracturing operations in order to limit the impact from discharges of these wastes into surface waters. Fracturing wastewater is also commonly injected underground for disposal - a practice which is subject to the SDWA underground injection program mentioned above.

6.5 Regulations in the pipeline

Finally, the EPA is also considering making rules under the Toxic Substances and Control Act (“TSCA”) to obtain data on chemical substances and mixtures used in hydraulic fracturing. Disclosure related to chemical substances used in hydraulic fracturing operations would also be required under rules recently proposed by the US Department of the Interior’s Bureau of Land Management (“BLM”) for fracturing operations on federal lands. The BLM has permitting authority for all fracturing operations on federal lands.

7. Market update

7.1 Recent developments

US natural gas prices have remained relatively low over the past several years as a result of abundant domestic supply and efficient production methods. Total natural gas consumption is high and, according to the EIA Annual Energy Outlook for 2013, consumption will continue to grow through at least 2040, in all end-use sectors except residential. Although prices have remained relatively low over the past several years, the EIA expects the cost of developing new incremental production needed to support continued growth in consumption and exports to result in a gradual rise in the Henry Hub spot price of about 2.4% per year, to around US$ 7.83 per million BTU in 2040. Prices remain low for now and the immediate future (around US$ 4 per million BTU) as producers continue to extract resources from the most productive and inexpensive areas, but prices will likely begin to rise after 2015.

Natural gas remains - and will likely continue to remain - far less expensive than crude oil on an energy-equivalent basis. It is also worth noting that the shale industry has seen a shift from shale gas activity toward liquid-rich shale plays, in part due to low natural gas prices, historically high
natural gas storage costs, increases in shale gas production, and a relatively mild winter of 2012-
13. Shale liquids, tied more closely to oil prices, have maintained high prices and good
economics, while shale gas and mostly dry gas plays have suffered. However, near-artic
conditions in the US over the 2013/2014 winter period have caused record spot price spikes in
regional market hubs, particularly on the East Coast. These spikes may lead to slight increases
in Henry Hub prices in the first half of 2014. Although, short term spikes are unlikely to have a
sustained impact on the low natural gas prices in the medium term.

The US consumed more natural gas than it produced in 2011, with net imports of almost 2 tcf. As
domestic supply has increased and prices have declined since 2011, making the US a less
attractive market and reducing US imports, exporting natural gas has become much more
attractive. The EIA projects that the US will become a net exporter of natural gas by 2020, as
export facilities clear regulatory approval and begin exporting over the coming years. The DOE
has “finally approved” one and “conditionally approved” four applications to export natural gas,
many from facilities on the Gulf Coast, and there are indications that the pace of export licence
reviews will soon increase following the completion of a DOE study concluding that exporting
natural gas would be a net benefit to the US economy. The DOE currently has around 20 export
applications pending and it is likely that some percentage of those applications will gain
approval.
7.2 Key shale basins

The EIA identified the following basins as having technically recoverable shale oil and shale gas resources in the US:

US Shale Gas and Shale Oil Key Plays

7.3 Companies

Given the advanced state of shale gas exploration and production in the US, individual companies are not listed in this section since the list would be extensive.
8. **Baker & McKenzie contacts**

Louis J. Davis  
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Louis.Davis@bakermckenzie.com

David P. Hackett  
Partner, Chicago  
David.Hackett@bakermckenzie.com
Shale Gas Aide-Mémoire

This Shale Gas Aide-Mémoire aims to provide a brief overview and comparison, for selected key issues, of the legal regimes applicable to conventional and unconventional hydrocarbons exploration and production in the Hot Countries.

1. Algeria

<table>
<thead>
<tr>
<th>Topic</th>
<th>Conventional</th>
<th>Unconventional</th>
</tr>
</thead>
<tbody>
<tr>
<td>Law/Regulations</td>
<td>Law no. 13-01 of 20 February 2013 amending and supplementing the Law no. 05-07 of 28 April 2005 relating to Hydrocarbons (&quot;HL&quot;)</td>
<td>Same as conventional</td>
</tr>
<tr>
<td>Exploration period⁹</td>
<td>• 7 years</td>
<td>• 11 years</td>
</tr>
<tr>
<td></td>
<td>• Exceptional extension of 6 months maximum to complete a well, provided the well started prior to end of exploration period</td>
<td>• Exceptional extension of 6 months maximum to complete a well, provided the well started prior to end of exploration period</td>
</tr>
<tr>
<td></td>
<td>• Exceptional extension of 2 years maximum to finish operations of delineation and/or evaluation of an exploratory well started 3 months prior to end of exploration period</td>
<td>• Exceptional extension of 2 years maximum to finish operations of delineation and/or evaluation of an exploratory well started 3 months prior to end of exploration period</td>
</tr>
<tr>
<td>Relinquishment</td>
<td>• Terms and conditions to be set out in the contract, provided that at the end of the exploration period, all the perimeter is relinquished</td>
<td>Same as conventional</td>
</tr>
<tr>
<td></td>
<td>• Preference to contractor having relinquished area</td>
<td></td>
</tr>
<tr>
<td>Exploitation period</td>
<td>• Oil or wet gas fields 32 years minus the duration of exploration period plus the retention period (3 years)</td>
<td>• 30 years for unconventional liquid hydrocarbons</td>
</tr>
<tr>
<td></td>
<td>• Dry gas fields: 32 years plus retention period plus 5 years</td>
<td>• 40 years for unconventional gaseous hydrocarbons</td>
</tr>
<tr>
<td></td>
<td>• Exploitation contracts: 25 years from the effective date of the contract</td>
<td>• Both can be extended by 10 years (i.e. 2 extensions of 5 years each)</td>
</tr>
<tr>
<td></td>
<td>• Dry gas fields: 30 years</td>
<td>• Unused exploration period is added to exploitation period</td>
</tr>
<tr>
<td>Delineation exploitation</td>
<td>The contracting entity must submit to the National Agency for the Development of Hydrocarbon Resources (&quot;ALNAFT&quot;) a development plan proposal including</td>
<td>Same as conventional</td>
</tr>
<tr>
<td>concession</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

⁹Investors can apply for a retention period during the exploration period, if there is no transportation infrastructure or market for gas. ALNAFT’s approval is necessary.
<table>
<thead>
<tr>
<th>Topic</th>
<th>Conventional</th>
<th>Unconventional</th>
</tr>
</thead>
<tbody>
<tr>
<td>a delineation of the exploitation perimeter</td>
<td></td>
<td></td>
</tr>
<tr>
<td>NOC participation and carry</td>
<td>51% minimum</td>
<td>Same as conventional</td>
</tr>
<tr>
<td>Flaring</td>
<td>N/A</td>
<td>• Gas flaring is forbidden; but, ALNAFT can grant exceptional authorisation subject to payment</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Tax payable of 8,000 Algerian Dinars/1000 m$^3$ flared gas</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Specific tariff in remote areas (i.e. no infrastructure to recover gas)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• No tax if (1) gas flared during exploration period or (2) gas flared during facilities start-up period</td>
</tr>
<tr>
<td>Water resources rights</td>
<td>• Tax for use of water must be paid</td>
<td>Same as conventional</td>
</tr>
<tr>
<td></td>
<td>• A licence must be issued by the relevant authority</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• The water must be used rationally and preferably reused</td>
<td></td>
</tr>
<tr>
<td>Economic stability</td>
<td>No express stability provisions are provided in the HL nor in the exploration and exploitation model contract</td>
<td>Same as conventional</td>
</tr>
<tr>
<td>DMO</td>
<td>• the Ministry of Energy and Mines can impose an obligation to supply liquid hydrocarbons to the domestic market in priority</td>
<td>Same as conventional</td>
</tr>
<tr>
<td></td>
<td>• Gas supply must meet the requirement of the domestic market in priority</td>
<td></td>
</tr>
<tr>
<td>3rd party and state access to infrastructure</td>
<td>Free access to pipeline transportation infrastructure and petroleum products storage infrastructure for third parties in exchange for payment of non-discriminatory tariff</td>
<td>Same as conventional</td>
</tr>
</tbody>
</table>
## Argentina

<table>
<thead>
<tr>
<th>Topic</th>
<th>Conventional</th>
<th>Unconventional</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Law/Regulations</strong></td>
<td>National legislation:</td>
<td>Same as conventional</td>
</tr>
<tr>
<td></td>
<td>• National Law No. 17,319</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• Law 26,197</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• Law 25,551</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• Law 25,943</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Legislation of the Province of Neuquén:</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• Hydrocarbons Law No. 2,453 of the Province of Neuquén</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• Provincial Executive Order 3,124 implementing Hydrocarbons Law No. 2,453</td>
<td></td>
</tr>
<tr>
<td></td>
<td>of the Province of Neuquén</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• Provincial Executive Order 1,447/2012</td>
<td></td>
</tr>
<tr>
<td><strong>Exploration period</strong></td>
<td>9 years - 13 years, depending on geological classification</td>
<td>Same as conventional</td>
</tr>
<tr>
<td><strong>Relinquishment</strong></td>
<td>Upon completion of:</td>
<td>Same as conventional</td>
</tr>
<tr>
<td></td>
<td>• the 1\textsuperscript{st} period: relinquish 50% of its permit area</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• the 2\textsuperscript{nd} period: relinquish 50% of the remaining permit area</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• the 3\textsuperscript{rd} period: return the entire remaining area</td>
<td></td>
</tr>
<tr>
<td><strong>Exploitation period</strong></td>
<td>• 25 years</td>
<td>Same as conventional</td>
</tr>
<tr>
<td></td>
<td>• 10-year extension</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• Non-elapsed terms of the exploration period may be added to the term of the</td>
<td></td>
</tr>
<tr>
<td></td>
<td>exploration concession</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• The maximum area of the exploitation concession not resulting from an</td>
<td></td>
</tr>
<tr>
<td></td>
<td>exploration permit is 250 km(^2)</td>
<td></td>
</tr>
<tr>
<td>**Delineation</td>
<td>• The boundaries of each parcel shall not exceed the retained area from the</td>
<td>Same as conventional</td>
</tr>
<tr>
<td>exploitation</td>
<td>exploration permit</td>
<td></td>
</tr>
<tr>
<td>concession**</td>
<td>• The maximum area of the exploration concession not resulting from an</td>
<td></td>
</tr>
<tr>
<td></td>
<td>exploration permit</td>
<td></td>
</tr>
<tr>
<td>**NOC participation</td>
<td>The terms of applying to bidding rounds may grant domestic companies carried</td>
<td>• Province of Neuquén may demand participatory share</td>
</tr>
<tr>
<td>and carry**</td>
<td>interests</td>
<td>of the products of exploitation</td>
</tr>
<tr>
<td></td>
<td>• Some areas are reserved for state-owned companies</td>
<td></td>
</tr>
<tr>
<td>Topic</td>
<td>Conventional</td>
<td>Unconventional</td>
</tr>
<tr>
<td>-------------------------------</td>
<td>-------------------------------------------------------------------------------</td>
<td>----------------------</td>
</tr>
<tr>
<td>Flaring</td>
<td>Highly restricted and only permitted on an exceptional basis</td>
<td>Same as conventional</td>
</tr>
<tr>
<td>Water resources rights</td>
<td>Companies that need to use large quantities of water to develop a hydrocarbons project must obtain a permit from the relevant provincial hydrological authority</td>
<td>Same as conventional</td>
</tr>
<tr>
<td>Economic stability</td>
<td>Within the Province of Neuquén, pursuant to Article 58 of the Law, the Province of Neuquén may not tax titleholders with new taxes or increase existing ones, except for overall increases in provincial taxes, those collected by the national government, or taxes that replace the latter.</td>
<td>Same as conventional</td>
</tr>
<tr>
<td>DMO</td>
<td>Executive Branch has the discretion to require that all hydrocarbons are made available for the domestic market</td>
<td>Same as conventional</td>
</tr>
<tr>
<td>3rd party and state access to infrastructure</td>
<td>Free access to pipeline transportation infrastructure and petroleum products storage infrastructure for third parties in exchange for payment of non-discriminatory tariff</td>
<td>Same as conventional</td>
</tr>
</tbody>
</table>
## Australia

<table>
<thead>
<tr>
<th>Topic</th>
<th>Conventional</th>
<th>Unconventional</th>
</tr>
</thead>
<tbody>
<tr>
<td>Law/Regulations</td>
<td>The Offshore Petroleum Act 2008 and The Offshore Petroleum and Greenhouse Gas Storage Act 2006 (&quot;Cth&quot;)</td>
<td>Same as conventional</td>
</tr>
<tr>
<td>Exploration period</td>
<td>Usually granted for a term of between 5 and 7 years and can be renewed</td>
<td>Same as conventional</td>
</tr>
</tbody>
</table>
| Relinquishment                | - There is often a requirement to relinquish portions of the title on renewal  
                               | - General rule: at the end of a permit term, one half of the total number of blocks contained by the permit area must be relinquished | There is often a requirement to relinquish portions of the title on renewal |
| Exploitation period           | - WA, SA and VIC: indefinite basis  
                               | - Remaining jurisdictions: varies between 20-30 years                        | Same as conventional |
| Delineation exploitation concession | - Exploitation area will be delineated in the production licence  
                                 | - Cth: a permit holder who discovers petroleum can have a "location" declared over the discovery  
                                 | - NSW: area must not be more than four blocks                                | Same as conventional |
| NOC participation and carry   | None                                                                         | Same as conventional |
| Flaring                       | N/A                                                                          | Must be in accordance with the laws or an environmental plan authorised by a regulator  
<pre><code>                           | - QLD: prohibited unless there is no other viable option                    |
</code></pre>
<p>| Water resources rights        | Water cannot be taken without a licence or permit issued under specific water rights legislation | Same as conventional |
| Economic Stabilisation        | N/A                                                                          | Same as conventional |
| DMO                           | WA: a domestic gas reservation policy where project participants must allocate 15% of annual production from the project to the domestic energy market | Same as conventional |</p>
<table>
<thead>
<tr>
<th>Topic</th>
<th>Conventional</th>
<th>Unconventional</th>
</tr>
</thead>
<tbody>
<tr>
<td>3\textsuperscript{rd} party and state access to infrastructure</td>
<td>Access to infrastructure is regulated primarily by the National Gas Law</td>
<td>Same as conventional</td>
</tr>
</tbody>
</table>
## 4. China

<table>
<thead>
<tr>
<th>Topic</th>
<th>Conventional Oil and Gas</th>
<th>Shale Gas</th>
</tr>
</thead>
<tbody>
<tr>
<td>Law/Regulations</td>
<td>Regulation on Sino-Foreign Cooperation in Exploitation of Onshore Petroleum Resources (&quot;Onshore Petroleum Regulation&quot;)</td>
<td>• 26 October 2012 Notice Regarding the Strengthening of Shale Gas Exploration, Prospecting, Supervision and Administration • 30 October 2013 Shale Gas Industry Policy • Regulations for conventional oil and gas, including the Onshore Petroleum Regulation</td>
</tr>
<tr>
<td>Exploration period</td>
<td>7 years aggregate divided into 3 phases</td>
<td>3 years</td>
</tr>
<tr>
<td>Relinquishment</td>
<td>• Voluntary relinquishment in general</td>
<td>Commitment to relinquishment is required in application for exploration licences</td>
</tr>
<tr>
<td></td>
<td>• Mandatory relinquishment not universally required</td>
<td></td>
</tr>
<tr>
<td>Exploitation period</td>
<td>10 - 30 years maximum depending on size of mine</td>
<td>Same as conventional</td>
</tr>
<tr>
<td>Delineation exploitation concession</td>
<td>Approved by the Ministry of Land and Resources following approval of the Ecological Prospecting and Reserve Report</td>
<td>Same as conventional</td>
</tr>
<tr>
<td>NOC participation and carry</td>
<td>• Foreign contractors are solely responsible for exploration operations and related investment risks • Sharing of production is agreed in relevant production sharing contract (&quot;PSC&quot;)</td>
<td>Same as conventional</td>
</tr>
<tr>
<td>Flaring</td>
<td>N/A</td>
<td>Same as conventional</td>
</tr>
<tr>
<td>Water resources rights</td>
<td>Requires water use licence and water resource fees</td>
<td>Same as conventional</td>
</tr>
<tr>
<td>Economic stability</td>
<td>N/A</td>
<td>Same as conventional</td>
</tr>
<tr>
<td>DMO</td>
<td>N/A</td>
<td>Same as conventional</td>
</tr>
<tr>
<td>3rd party and state access to infrastructure</td>
<td>• No legislation • Addressed in PSCs</td>
<td>Same as conventional</td>
</tr>
</tbody>
</table>
5. Poland

<table>
<thead>
<tr>
<th>Topic</th>
<th>Conventional</th>
<th>Unconventional</th>
</tr>
</thead>
<tbody>
<tr>
<td>Law/Regulations</td>
<td>• Directive 94/22/EC</td>
<td>Act of Mining and Geological Law</td>
</tr>
<tr>
<td></td>
<td>• Polish Civil Code</td>
<td></td>
</tr>
<tr>
<td>Exploration period</td>
<td>• Maximum 50 years</td>
<td>Same as conventional</td>
</tr>
<tr>
<td></td>
<td>• In practice 10 years</td>
<td></td>
</tr>
<tr>
<td>Relinquishment</td>
<td>• Concessions may be relinquished by the concession holder</td>
<td>Same as conventional</td>
</tr>
<tr>
<td></td>
<td>• Specific terms and conditions of relinquishments are set out in the mining usufruct agreement</td>
<td></td>
</tr>
<tr>
<td>Exploitation period</td>
<td>• Maximum 50 years</td>
<td>Same as conventional</td>
</tr>
<tr>
<td></td>
<td>• In practice 10 years</td>
<td></td>
</tr>
<tr>
<td>Delineation exploitation concession</td>
<td>• Specified in the concession and mining usufruct agreement</td>
<td>Same as conventional</td>
</tr>
<tr>
<td></td>
<td>• Exploration concession may not exceed 1200 km²</td>
<td></td>
</tr>
<tr>
<td>NOC participation and carry</td>
<td>None</td>
<td>Currently none, but draft regulations being worked on by the Polish government provide for a NOC carry</td>
</tr>
<tr>
<td>Flaring</td>
<td>Gas that will not be marketed and exceeds operational requirements can be flared without obtaining consent from the Ministry of Environment</td>
<td>Same as conventional</td>
</tr>
<tr>
<td>Water resources rights</td>
<td>• Water permit may be issued if the proposed activity will not contravene health or environmental requirements</td>
<td>Same as conventional</td>
</tr>
<tr>
<td></td>
<td>• A permit is not required if the water intake does not exceed 5m³ per day or if it is for the purpose of drilling or performing explosive boreholes</td>
<td></td>
</tr>
<tr>
<td>Economic stability</td>
<td>None</td>
<td>Same as conventional</td>
</tr>
<tr>
<td>DMO</td>
<td>None</td>
<td>Same as conventional</td>
</tr>
<tr>
<td>3rd party and state access to infrastructure</td>
<td>The Polish Energy Law stipulates provisions which guarantee third party access to gas networks</td>
<td>Same as conventional</td>
</tr>
</tbody>
</table>
### 6. Russia

<table>
<thead>
<tr>
<th>Topic</th>
<th>Conventional</th>
<th>Unconventional</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Law/Regulations</strong></td>
<td>• Subsoil Law of 21 February 1992</td>
<td>Same as conventional</td>
</tr>
<tr>
<td></td>
<td>• Federal Law on Production Sharing Agreements of 30 December 1995</td>
<td></td>
</tr>
<tr>
<td><strong>Exploration period</strong></td>
<td>5-7 years</td>
<td>Same as conventional</td>
</tr>
<tr>
<td><strong>Relinquishment</strong></td>
<td>None</td>
<td>Same as conventional</td>
</tr>
<tr>
<td><strong>Exploitation period</strong></td>
<td>The life of the project</td>
<td>Same as conventional</td>
</tr>
<tr>
<td><strong>Delineation exploitation concession</strong></td>
<td>N/A</td>
<td>Same as conventional</td>
</tr>
<tr>
<td><strong>NOC participation and carry</strong></td>
<td>N/A</td>
<td>Same as conventional</td>
</tr>
<tr>
<td><strong>Flaring</strong></td>
<td>Not prohibited</td>
<td>Same as conventional</td>
</tr>
<tr>
<td><strong>Water resources rights</strong></td>
<td>To be acquired separately from owners of water resources</td>
<td>Same as conventional</td>
</tr>
<tr>
<td><strong>Economic stability</strong></td>
<td>• Possible in PSAs</td>
<td>Same as conventional</td>
</tr>
<tr>
<td></td>
<td>• Also possible for foreign investors subject to certain conditions</td>
<td></td>
</tr>
<tr>
<td><strong>DMO</strong></td>
<td>No DMO established by law, but may be included in licence or PSA</td>
<td>Same as conventional</td>
</tr>
<tr>
<td><strong>3rd party and state access to infrastructure</strong></td>
<td>Only with respect to those facilities that are deemed to be natural monopoly facilities</td>
<td>Same as conventional</td>
</tr>
</tbody>
</table>
### 7. South Africa

<table>
<thead>
<tr>
<th>Topic</th>
<th>Conventional</th>
<th>Unconventional</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Law/Regulations</strong></td>
<td>Mineral and Petroleum Resources Development Act, 2002, as amended by the</td>
<td>Same as</td>
</tr>
<tr>
<td></td>
<td>Mineral and petroleum Resources Development Amendment Act, 2008 (&quot;MPRDA&quot;)</td>
<td>conventional</td>
</tr>
<tr>
<td><strong>Exploration period</strong></td>
<td>Not more than 9 years (3 year initial period which may be renewed for a</td>
<td>Same as</td>
</tr>
<tr>
<td></td>
<td>maximum of 3 periods not exceeding 2 years each)</td>
<td>conventional</td>
</tr>
<tr>
<td><strong>Relinquishment</strong></td>
<td>No relinquishment obligations in legislation. However, in practice, upon</td>
<td>Same as</td>
</tr>
<tr>
<td></td>
<td>renewal:</td>
<td>conventional</td>
</tr>
<tr>
<td></td>
<td>• 20% of the exploration area on 1st renewal</td>
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</tr>
<tr>
<td></td>
<td>• a further 15% of the exploration area on 2nd renewal</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• a further 15% of the exploration area on 3rd renewal</td>
<td></td>
</tr>
<tr>
<td><strong>Exploitation period</strong></td>
<td>• Initial period not to exceed 30 years</td>
<td>Same as</td>
</tr>
<tr>
<td></td>
<td>• Capable of renewal for further periods not exceeding 30 years each</td>
<td>conventional</td>
</tr>
<tr>
<td></td>
<td>• No limit on number of renewals permitted</td>
<td></td>
</tr>
<tr>
<td><strong>Delineation exploitation</strong></td>
<td>No limit</td>
<td>Same as</td>
</tr>
<tr>
<td><strong>concession</strong></td>
<td></td>
<td>conventional</td>
</tr>
<tr>
<td><strong>NOC participation and carry</strong></td>
<td>• Option granted to the state in terms of the right to acquire a maximum</td>
<td>Same as</td>
</tr>
<tr>
<td></td>
<td>participating interest of 10%</td>
<td>conventional</td>
</tr>
<tr>
<td></td>
<td>• A minimum of 10% participation interest for Historically Disadvantaged</td>
<td></td>
</tr>
<tr>
<td></td>
<td>South Africans</td>
<td></td>
</tr>
<tr>
<td><strong>Flaring</strong></td>
<td>N/A</td>
<td>To be conducted</td>
</tr>
<tr>
<td></td>
<td></td>
<td>in accordance</td>
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<td></td>
<td></td>
<td>with the</td>
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<td></td>
<td></td>
<td>standards that</td>
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<td></td>
<td></td>
<td>have been</td>
</tr>
<tr>
<td></td>
<td></td>
<td>prescribed by</td>
</tr>
<tr>
<td></td>
<td></td>
<td>the Minister of</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Water and</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Environmental</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Affairs in</td>
</tr>
<tr>
<td></td>
<td></td>
<td>terms of the</td>
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<tr>
<td></td>
<td></td>
<td>National</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Environmental</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Management</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Waste Act 2008</td>
</tr>
<tr>
<td><strong>Water resources</strong></td>
<td>Users of water must apply for licences in respect of a particular water use</td>
<td>Same as</td>
</tr>
<tr>
<td><strong>rights</strong></td>
<td></td>
<td>conventional</td>
</tr>
<tr>
<td><strong>Economic</strong></td>
<td>The MPRDA does not address</td>
<td>Same as</td>
</tr>
<tr>
<td></td>
<td></td>
<td>conventional</td>
</tr>
<tr>
<td>Topic</td>
<td>Conventional</td>
<td>Unconventional</td>
</tr>
<tr>
<td>-------------------------------</td>
<td>------------------------------------------------------------------------------</td>
<td>-------------------------------</td>
</tr>
<tr>
<td>stability</td>
<td>stability</td>
<td></td>
</tr>
</tbody>
</table>
| DMO                           | May be imposed by the National Energy Regulator of South Africa ("NERSA") as part of the conditions attached to a licence for:  
• the construction or operation of a petroleum pipeline, loading facility and/or storage facility  
• gas trading                     | Same as conventional          |
| 3rd party and state access to infrastructure | • Third party access on commercially reasonable terms may be imposed by NERSA as part of the conditions attached to a licence for the construction or operation of a petroleum pipeline, loading facility and/or storage facility  
• The state does not have a preferential right of access/use to piped gas infrastructure | Same as conventional          |
<table>
<thead>
<tr>
<th>Topic</th>
<th>Conventional</th>
<th>Unconventional</th>
</tr>
</thead>
<tbody>
<tr>
<td>Law/Regulations</td>
<td>The Petroleum Act 1998</td>
<td>Same as conventional</td>
</tr>
<tr>
<td>Exploration period</td>
<td>Petroleum Exploration and Development Licences (&quot;PEDLs&quot;):</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• 6 years (exploration)</td>
<td>Same as conventional</td>
</tr>
<tr>
<td></td>
<td>• 5 years (appraisal)</td>
<td></td>
</tr>
<tr>
<td>Relinquishment</td>
<td>For PEDLs, the licensee must relinquish a fixed amount of acreage (usually 50%) at the end of the 6 years exploration</td>
<td>Same as conventional</td>
</tr>
<tr>
<td>Exploitation period</td>
<td>PEDLs: 20 years</td>
<td>Same as conventional</td>
</tr>
<tr>
<td>Delineation exploitation concession</td>
<td>None</td>
<td>Same as conventional</td>
</tr>
<tr>
<td>NOC participation and carry</td>
<td>None</td>
<td>Same as conventional</td>
</tr>
<tr>
<td>Flaring</td>
<td>• ≤ 10 tonnes per day, no permit nor consent required</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• &gt; 10 tonnes per day, but &lt; 50 tonnes per day, an environmental permit from the Environment Agency and an annual flare consent are required</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• &gt; 50 tonnes per day, an environmental permit from the Environment Agency and a longer term flare consent can be applied for with a less rigorous application process</td>
<td>Same as conventional</td>
</tr>
<tr>
<td>Water resources rights</td>
<td>Environmental permit from the Environmental Agency required for:</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• any groundwater activity (save for contrary opinion of the Environmental Agency)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• water discharge activity</td>
<td>Same as conventional</td>
</tr>
<tr>
<td></td>
<td>• to extract more than 20 m³/d of water</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• if the proposed site is near a watercourse or main river</td>
<td></td>
</tr>
<tr>
<td>Economic stability</td>
<td>None</td>
<td>Same as conventional</td>
</tr>
<tr>
<td>DMO</td>
<td>No system of reservation of petroleum for local use, save for in</td>
<td>Same as conventional</td>
</tr>
</tbody>
</table>

8. **UK**
<table>
<thead>
<tr>
<th>Topic</th>
<th>Conventional</th>
<th>Unconventional</th>
</tr>
</thead>
<tbody>
<tr>
<td>the event of an emergency</td>
<td></td>
<td></td>
</tr>
<tr>
<td>3rd party and state access to infrastructure</td>
<td>The Energy Act 2011 and Infrastructure Code of Practice provide a third party access regime</td>
<td>Same as conventional</td>
</tr>
</tbody>
</table>
9. Ukraine

<table>
<thead>
<tr>
<th>Topic</th>
<th>Conventional</th>
<th>Unconventional</th>
</tr>
</thead>
<tbody>
<tr>
<td>Law/Regulations</td>
<td>• Subsoil Code 1994</td>
<td>Same as conventional</td>
</tr>
<tr>
<td></td>
<td>• Oil and Gas Law 2001</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• Water Code</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• Production Sharing Agreement (PSA) Law 1999 (“PSA Law”)</td>
<td></td>
</tr>
<tr>
<td>Exploration period</td>
<td>• 5 years onshore</td>
<td>Same as conventional</td>
</tr>
<tr>
<td></td>
<td>• 10 years offshore</td>
<td></td>
</tr>
<tr>
<td>Relinquishment</td>
<td>Relinquishments constitute an essential condition of a PSA and a procedure for relinquishment must be set out in each PSA</td>
<td>Same as conventional</td>
</tr>
<tr>
<td></td>
<td>• Same as conventional</td>
<td>One of the existing PSAs has a term of 50 years (45 years' exploitation and 5 years' exploration period)</td>
</tr>
<tr>
<td>Exploitation period</td>
<td>• 20 years onshore</td>
<td>Same as conventional</td>
</tr>
<tr>
<td></td>
<td>• 30 years offshore</td>
<td>One existing PSA has a term of 50 years (45 years' exploitation and 5 years' exploration period)</td>
</tr>
<tr>
<td>Delineation exploitation concession</td>
<td>• 500 km² maximum for onshore permits (save for special permits)</td>
<td>Same as conventional</td>
</tr>
<tr>
<td></td>
<td>• 1,000 km² maximum for offshore permits (Black Sea)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• For special permits issued pursuant to PSAs, the permit area shall match the borders of the subsurface area, specified in the special permit (i.e. in effect the special permit may cover onshore areas in excess of 500 km²)</td>
<td></td>
</tr>
<tr>
<td>NOC participation and carry</td>
<td>State participation is obligatory and is determined when PSAs are being tendered</td>
<td>Same as conventional</td>
</tr>
<tr>
<td>Flaring</td>
<td>N/A</td>
<td>Right to flare in exceptional circumstances</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Flaring has been specifically</td>
</tr>
<tr>
<td>Topic</td>
<td>Conventional</td>
<td>Unconventional</td>
</tr>
<tr>
<td>-------------------------------</td>
<td>------------------------------------------------------------------------------</td>
<td>-------------------------------------------------------------------------------</td>
</tr>
<tr>
<td><strong>Water resources rights</strong></td>
<td>Special permits (3-25 years) may be granted in accordance with the Water Code</td>
<td>Same as conventional</td>
</tr>
<tr>
<td><strong>Economic stability</strong></td>
<td>• Article 27 of the PSA Law provides for economic stabilisation</td>
<td>Same as conventional</td>
</tr>
<tr>
<td></td>
<td>• Amendments and/or supplements to laws and/or regulations, which are made after the PSA becomes effective, shall not apply to the Investor except those related to defence; national security; public order and environmental protection</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• If a change in law and/or regulations has a significant adverse impact on economic benefits (including those stemming from the fiscal conditions) which an investor enjoys under a PSA or which are provided to an investor during a PSA term, the parties amend such PSA or perform such other acts to restore the overall economic benefit for the investor</td>
<td></td>
</tr>
<tr>
<td><strong>DMO</strong></td>
<td>• Under Article 22 of the PSA Law, a PSA may require an investor to sell part of the hydrocarbons extracted to the state or a particular enterprise in Ukraine</td>
<td>Same as conventional</td>
</tr>
<tr>
<td></td>
<td>• Subject to the above, investors are free to dispose of part of their production under the PSA at their own discretion. This includes selling gas outside Ukraine at market prices</td>
<td></td>
</tr>
<tr>
<td><strong>3rd party and state access to infrastructure</strong></td>
<td>• Access to the local or the main pipeline network must be provided by the operator on a non-discriminatory basis and can only be refused with grounds</td>
<td>Same as conventional</td>
</tr>
<tr>
<td></td>
<td>• To date, there are no private pipelines operators in Ukraine. However, PSA Law has recently been amended to provide PSA investors with the right to construct and operate pipelines</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• One existing PSA provides that each party must make every reasonable effort to make capacity available to each of the other parties to that PSA, if the infrastructure it owns exceeds its own needs</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• The other existing PSA provides that third parties are allowed to transport their hydrocarbons through any pipeline constructed</td>
<td></td>
</tr>
<tr>
<td>Topic</td>
<td>Conventional</td>
<td>Unconventional</td>
</tr>
<tr>
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<tr>
<td></td>
<td></td>
<td>by the investor under such conditions as are approved by the investor and the state, provided such conditions are non-discriminatory and commercially reasonable</td>
</tr>
</tbody>
</table>
### 10. US

<table>
<thead>
<tr>
<th>Topic</th>
<th>Summary</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ownership of hydrocarbons</td>
<td>Most minerals are privately owned. Agreements for exploration and production are freely negotiated between the mineral owner and exploration production company</td>
</tr>
<tr>
<td>Regulations on hydraulic fracturing</td>
<td>Regulated at state level:</td>
</tr>
<tr>
<td></td>
<td>• Allowed in most states, including all major shale states (Texas, Louisiana, North Dakota, Pennsylvania, Oklahoma, Arkansas, West Virginia and Ohio)</td>
</tr>
<tr>
<td></td>
<td>• Banned in Vermont</td>
</tr>
<tr>
<td></td>
<td>• Moratorium in New York</td>
</tr>
<tr>
<td></td>
<td>• De facto moratorium in Maryland</td>
</tr>
<tr>
<td></td>
<td>Disclosure of hydraulic fracturing fluids required in most states</td>
</tr>
<tr>
<td>Cross-unit lateral wells</td>
<td>Regulated at state level. Regulatory approaches include:</td>
</tr>
<tr>
<td></td>
<td>• Forced pooling</td>
</tr>
<tr>
<td></td>
<td>• Lease integration</td>
</tr>
<tr>
<td></td>
<td>• Allocation wells</td>
</tr>
<tr>
<td>Permitting for wells</td>
<td>Regulated by each state's regulatory agency for oil and gas exploration (e.g. Railroad Commission of Texas)</td>
</tr>
<tr>
<td>Regulation of water usage</td>
<td>• Regulated at federal level</td>
</tr>
<tr>
<td></td>
<td>• All states regulate construction and use of waste storage facilities and require reporting of usage</td>
</tr>
<tr>
<td>Environmental regulations</td>
<td>Mostly regulated at federal level and enforced by Environmental Protection Agency:</td>
</tr>
<tr>
<td></td>
<td>• Safe Drinking Water Act</td>
</tr>
<tr>
<td></td>
<td>• Clean Water Act</td>
</tr>
<tr>
<td></td>
<td>• Clean Air Act</td>
</tr>
<tr>
<td></td>
<td>• Resources Conservation and Recovery Act</td>
</tr>
<tr>
<td></td>
<td>• Comprehensive Environmental Response, Compensation and Liability Act</td>
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## Glossary

<table>
<thead>
<tr>
<th>Defined term</th>
<th>Definition</th>
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<tbody>
<tr>
<td>CIS</td>
<td>Commonwealth of Independent States</td>
</tr>
<tr>
<td>DMO</td>
<td>Domestic Market Obligation</td>
</tr>
<tr>
<td>EIA</td>
<td>US Energy Information Administration</td>
</tr>
<tr>
<td>EIA Report</td>
<td>EIA June 2013 report on unconventional resources</td>
</tr>
<tr>
<td>EU</td>
<td>European Union</td>
</tr>
<tr>
<td>fracking</td>
<td>Hydraulic Fracturing</td>
</tr>
<tr>
<td>Guide</td>
<td>this guide</td>
</tr>
<tr>
<td>Hot Countries</td>
<td>the 10 countries presented in this booklet, namely: Algeria, Argentina, Australia, China, Poland, Russia, South Africa, UK, Ukraine and US</td>
</tr>
<tr>
<td>IEA</td>
<td>International Energy Agency</td>
</tr>
<tr>
<td>IOC</td>
<td>International Oil and Gas Company</td>
</tr>
<tr>
<td>LNG</td>
<td>liquefied natural gas</td>
</tr>
<tr>
<td>NOC</td>
<td>National Oil and Gas Company</td>
</tr>
<tr>
<td>PetroChina</td>
<td>PetroChina Company Limited</td>
</tr>
<tr>
<td>PSA</td>
<td>Production Sharing Agreement</td>
</tr>
<tr>
<td>tcf</td>
<td>trillion cubic feet</td>
</tr>
<tr>
<td>US</td>
<td>United States</td>
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</tbody>
</table>
Annex - EIA Data

Below is the EIA data, from the EIA Report, for technically recoverable shale gas resources. This data was used to create the graphs and charts in this Guide.

<table>
<thead>
<tr>
<th>Country</th>
<th>Technically recoverable resources ( tcf)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Algeria</td>
<td>707</td>
</tr>
<tr>
<td>Argentina</td>
<td>802</td>
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<tr>
<td>Australia</td>
<td>437</td>
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<tr>
<td>Austria</td>
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<tr>
<td>Brazil</td>
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<tr>
<td>Bolivia</td>
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<td>Bulgaria</td>
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<tr>
<td>Canada</td>
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<tr>
<td>Chile</td>
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<tr>
<td>China</td>
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<tr>
<td>Colombia</td>
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<tr>
<td>Czech Republic</td>
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<td>Denmark</td>
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<td>Egypt</td>
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<td>France</td>
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<td>Germany</td>
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<td>Hungary</td>
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<td>India</td>
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<td>Indonesia</td>
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<td>Jordan</td>
<td>7</td>
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<tr>
<td>Mexico</td>
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<td>Morocco</td>
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<table>
<thead>
<tr>
<th>Country</th>
<th>Technically recoverable resources ( tcf)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mongolia</td>
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<tr>
<td>Netherlands</td>
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<tr>
<td>Pakistan</td>
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<td>Paraguay</td>
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<tr>
<td>Poland</td>
<td>148</td>
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<tr>
<td>Republic of Ireland</td>
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<tr>
<td>Romania</td>
<td>287</td>
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<td>Russia</td>
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<tr>
<td>Saudi Arabia</td>
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<tr>
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<td>390</td>
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<td>Spain</td>
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<tr>
<td>Sweden</td>
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<tr>
<td>Ukraine</td>
<td>128</td>
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<td>Uruguay</td>
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<td>Thailand</td>
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<td>Tunisia</td>
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<td>Turkey</td>
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<tr>
<td>United Kingdom</td>
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<td>US</td>
<td>665</td>
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<tr>
<td>Venezuela</td>
<td>167</td>
</tr>
<tr>
<td>Western Sahara</td>
<td>8</td>
</tr>
</tbody>
</table>
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We understand the challenges of the global economy because we have been at the forefront of its evolution. Since 1949, we have advised leading corporations on the issues of today's integrated world market. We have cultivated the culture, commercial pragmatism and technical and interpersonal skills required to deliver world-class service tailored to the preferences of world-class clients worldwide.

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